COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

RECEIVED

JAN 27 2012

PUBLIC SERVICE COMMISSION

IN THE MATTER OF

APPLICATION OF KENTUCKY POWER COMPANY)	
FOR APPROVAL OF ITS ENVIRONMENTAL)	
SURCHARGE PLAN, APPROVAL OF ITS AMENDED)	
ENVIORNMENTAL COST RECOVERY)	CASE NO. 2011-00401
SURCHARGE TARIFFS, AND FOR THE GRANT OF)	
CERTIFICATES OF PUBLIC CONVENIENCE AND)	
NECESSITY FOR THE CONSTRUCTION AND)	
ACQUISTION OF RELATED FACILITIES)	

RESPONSES OF KENTUCKY POWER COMPANY TO
SIERRA CLUB'S INITIAL SET OF DATA REQUESTS

January 27, 2012

VERIFICATION

The undersigned, KARL R. BLETZACKER, being duly sworn, deposes and says he is Director, Fundamental Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

Karl R Bletzacker

KARL R. BLETZACKER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Karl R. Bletzacker, this the 25th day of January 2012.

NOTARIAL SEAL
STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

Cheryl L. Strawser
Notary Public

My Commission Expires: October 1, 2016

VERIFICATION

The undersigned, John M. McManus, being duly sworn, deposes and says he is Vice President Environmental Services for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

John M. McManus

John M. McManus

STATE OF OHIO	)	
	)	CASE NO. 2011-00401
COUNTY OF FRANKLIN	)	

Subscribed and sworn to before me, a Notary Public in and before said County and State, by John M. McManus, this the 16 day of January 2012.

Janet L. White

Notary Public

JANET L. WHITE
Notary Public, State of Ohio
My Commission Expires: My Commission Expires 09-09-2013

VERIFICATION

The undersigned, Lila P. Munsey, being duly sworn, deposes and says she is the Manager, Regulatory Services for Kentucky Power, that she has personal knowledge of the matters set forth in the forgoing responses for which she is the identified witness and that the information contained therein is true and correct to the best of her information, knowledge, and belief

Lila P. Munsey

Lila P. Munsey

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Lila P. Munsey, this 20th day of January 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

VERIFICATION

The undersigned, TOBY THOMAS, being duly sworn, deposes and says he is Managing Director, Kentucky Power Generation, Gas, Renewals and Planning for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief.

TOBY THOMAS

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Toby Thomas, this the 25th day of January 2012.

Notary Public

My Commission Expires: 1/04/2014

DONNA J. STEPHENS
Notary Public, State of Ohio
My Commission Expires 01-04-2014

VERIFICATION

The undersigned, ROBERT L. WALTON being duly sworn, deposes and says he is Managing Director Projects and Controls for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

ROBERT L. WALTON

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Robert L. Walton, this the 30 day of January 2012.

Notary Public

My Commission Expires: 5-29-2012

Notary Public

VERIFICATION

The undersigned, SCOTT C. WEAVER, being duly sworn, deposes and says he is Managing Director Resource Planning and Operation Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge and belief

SCOTT C. WEAVER

STATE OF OHIO)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Scott C. Weaver, this the 24th day of January 2012.

Notary Public

NOTARIAL SEAL
STATE OF OHIO

Cheryl L. Strawser
Notary Public, State of Ohio
My Commission Expires 10-01-2016

My Commission Expires: October 1, 2016

VERIFICATION

The undersigned, Ranie K. Wohnhas, being duly sworn, deposes and says he is the Managing Director Regulatory and Finance for Kentucky Power, that he has personal knowledge of the matters set forth in the forgoing responses for which he is the identified witness and that the information contained therein is true and correct to the best of his information, knowledge, and belief

Ranie K. Wohnhas

Ranie K. Wohnhas

COMMONWEALTH OF KENTUCKY)
) CASE NO. 2011-00401
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Ranie K. Wohnhas, this the 20th day of January, 2012.

Judy K Rosquist

Notary Public

My Commission Expires: January 23, 2013

Kentucky Power Company

REQUEST

Please provide all reports, memoranda, presentations, or other documents provided to stockholders, investors, balks, investment firms, investment brokers or dealers, investment analysts, bond rating agencies from either KPC or AEP or the like between 2005 and 2012 (inclusive) including:.

a. the environmental compliance status of either unit of the Big Sandy plant,

b. past, present or future environmental compliance of the Big Sandy plant,

c. litigation or settlements concerning the Big Sandy plant, to the extent not covered by attorney-client privilege,

d. past, present or future need for the Big Sandy plant, or the need for or plans for capital additions to the Coal Plants, whether for environmental compliance or otherwise, and

e. any other matter that could affect the costs or output of the Big Sandy plant.

f. To the extent not already provided in response to the above request, please provide any agendas, handouts, minutes documents prepared for or resulting from each meeting of KPC or AEP with stockholders, investors, banks, investments firms, investment brokers or dealers, investment analysts, bond rating agencies or the like at which the matters listed above were discussed in any way.

g. Please continue to provide any such documentation as listed in (a)-(f) above as generated in 2012 on a regular basis.

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP.") AEP is not a party to this proceeding, and is not a utility subject to the jurisdiction of the Public Service Commission of Kentucky. AEP is not obligated to assist Kentucky Power in financing the proposed environmental projects in Kentucky Power's 2011 Environmental Compliance Plan. Without waiving this objection, please see the enclosed CD.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

To the extent not already provided in response to this request or another, please provide any analyses, performed by or for KPC or AEP during the past seven years, of the need for the Big Sandy plant, the need for and cost of necessary or potentially necessary capital additions to the Big Sandy plant, or the environmental effects of and risks from continued operation of the Big Sandy plant. If already provided in response to another request, please identify the request and the relevant document provided.

RESPONSE

Kentucky Power objects to this Request beyond the two studies identified below as being unduly burdensome and as seeking information that is irrelevant and not likely to lead to the production of admissible evidence.

An independent analysis was performed by Parsons E&C dated December 30,2004, and titled Big Sandy Plant, Unit 2 WFGD Project Phase I Report - Report No. AEBS-2_LI-012-0001, Rev. 0. Please see the response to Sierra 1-27a.

A Draft Special Waste Landfill Permit application for a FGD Disposal Facility was prepared by FMSM Engineers (Fuller, Mossbarger, Scott & May) dated July 28,2006. The application is voluminous and may be reviewed upon request at the offices of the Company's counsel, 421 W. Main St. Frankfort, KY 40601.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide a non-redacted, full color or original digital copy of any Integrated Resource Plans constructed and/or filed by either KPC or AEP between 2005 and 2012.

RESPONSE

KPCo objects to this request to the extent it requests information that is proprietary and confidential and protected by KRS 61.878. Specifically, the information contained in Volume D of the IRP was granted confidential treatment by letter from the Commission dated December 11, 2009, in Case No. 2009-00339. Without waiving the objection, Volume D will be provided to those parties executing a non-disclosure agreement.

Please see enclosed CD containing the following files: 1) KPCo 2009 IRP Volume A; 2) KPCo 2009 IRP Volume B; 3) KPCo 2009 IRP Volume C; 4) AEP East 2009 IRP; and 5) AEP East 2010 IRP. KPCo 2009 IRP Volume D is filed subject to the accompanying petition for confidential treatment.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide any strategic documents generated between 2005 and 2012 (inclusive) by company or other parties working for the company regarding mechanisms by which the company could or should comply with environmental regulations, including air quality compliance planning, water quality planning, and solid waste compliance planning.

RESPONSE

The requested information is confidential and proprietary and its public disclosure will result in competitive injury to Kentucky Power. The information is being produced subject to the accompanying petition for confidential treatment.

Please see the accompanying CD for the requested information.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Please provide any technical documents generated between 2005 and 2012 (inclusive) by company or other parties working for the company regarding mechanisms by which the company could or should comply with environmental regulations, including air quality compliance planning, water quality planning, and solid waste compliance planning.

RESPONSE

The requested information is confidential and proprietary and its public disclosure will result in competitive injury to Kentucky Power. The information is being produced subject to the accompanying petition for confidential treatment.

Please see the accompanying CD for the requested information. Also, please see the Company's response to KPSC 1-35, Attachment 1 for the Big Sandy Unit 2 FGD – NID IAQCS Technical Due Diligence Review.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

To the extent that such documents are not already in the public record, and not covered by attorney-client privilege, please provide copies of email and hard-copy correspondence, presentations, and other data shared with the US EPA, DOJ, and the Kentucky DEP regarding the Company's environmental retrofits and environmental planning for air, water, and solid waste environmental compliance. Provide documentation from 2007 through 2012, inclusive.

RESPONSE

There are no such documents.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Please provide a record of all correspondence covered by attorney-client privilege with the agencies listed in the above request, including correspondent, subject, date, and medium of correspondence.

RESPONSE

The Company is unaware of any such documents.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Please describe current demand-side management (DSM) programs offered by AEP and KPC, including demand-response, interruptible load, and efficiency programs. Please note the cost, MW or MWh reductions, expected life, and penetration of these programs.

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP.") AEP is not a party to this proceeding, and is not a utility subject to the jurisdiction of the Public Service Commission of Kentucky.

A description of the current DSM programs offered by Kentucky Power is provided with the residential and business promotion sheets shown on Attachments 1 and 2.

The DSM program activity levels including program expense is shown on Attachment 3. DSM programs are normally evaluated on a three-year cycle and considered for renewal based on various factors including the program cost and benefits.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please describe proposed DSM programs to be offered by AEP and KPC, including demand-response, interruptible load, and efficiency programs. Please note the cost, MW or MWh reductions, expected life, and penetration of these programs. Please describe if or how these programs are incorporated into the current case, and provide workpapers showing such, if applicable.

RESPONSE

Kentucky Power objects to the request to the extent it seeks information regarding American Electric Power, Inc. ("AEP.") AEP is not a party to this proceeding, and is not a utility subject to the jurisdiction of the Public Service Commission of Kentucky.

Kentucky Power Company has filed and received approval of 10 DSM programs between 2009 and 2011, but currently has no new proposed DSM programs before the Commission.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Please provide any DSM potential studies performed by or for AEP and/or KPC in the last five years, including attendant workbooks or calculations. Please describe if or how these studies are incorporated into the current case. If they are not, why not?

RESPONSE

Please see the attachments to this response. All of the programs described in the attachments were approved by the Commission and implemented by the Company.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 8, lines 13 to 17.

a. Please provide all assumptions and workpapers underlying the estimate of lost jobs and compensation presented on lines 13 and 14.

b. Is the estimate of existing jobs lost due to retiring Big Sandy Unit 2 net of new jobs that would be created by the operation of a replacement gas unit? If no, why not? If yes, please demonstrate how those new jobs were estimated and considered.

c. Please provide all assumptions and workpapers underlying the estimate of reduced payroll and property taxes presented on line 17.

RESPONSE

a-c. Please refer to the Company's response to KPSC 1-80 and 81.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 8, lines 17 to 21.

a. Please provide all assumptions and workpapers underlying the estimate of the direct and indirect economic impact of sales of Kentucky coal to the Big Sandy plant presented on lines 19 to 21. Please disaggregate these estimates between coal sales to Unit 1 and coal sales to Unit 2.

b. Please provide the quantity of Kentucky coal the Company has purchased for Big Sandy Unit 1 and Unit 2 respectively in the most recent five calendar years for which statistics are available.

c. Is it Mr. Wohnhas' position that replacement of generation from Big Sandy Unit 2 with generation from a new gas unit would eliminate 100 percent of the direct and indirect economic impact of sales of Kentucky coal to the Big Sandy plant presented on lines 19 to 21. If no, what is Mr. Wohnhas position?

d. Does Mr. Wohnhas agree that Kentucky coal mining companies could sell the annual quantity of coal they have historically sold to Big Sandy Unit 2 to customers in other states if Big Sandy Unit 2 is retired? If Mr. Wohnhas does not agree please provide all analyses upon which Mr. Wohnhas bases his answer.

RESPONSE

a. Please refer to the Company's response to KPSC 1-82.

b. KPCo does not purchase coal separately for Big Sandy Units 1 and 2, but for the plant as a whole. See the table below for the tons of Kentucky coal purchased for the Big Sandy Plant for 2007 through 2011.

Year	Tons of Kentucky Coal Delivered
2007	1,575,684
2008	1,536,848
2009	1,668,522
2010	982,474
2011*	1,302,110

* Only includes tons delivered through November 2011

c. Yes.

d. Kentucky Power is not in a position to speculate as to the existence of such sales or the terms upon which they might be made.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 9, lines 3 to 13.

a. Please provide the preliminary analysis noted on line 8, with all supporting assumptions and calculations.

b. Please reconcile the testimony of Mr. Wohnhas regarding socio-economic benefits of continuing to operate Big Sandy Unit 2, rather than replace it with a gas unit, with the Company's June 9, 2011 announced intention to replace the Big Sandy units with a gas unit.

RESPONSE

a. Please refer to the Company's responses to KPSC 1-84 and 85.

b. As stated in my testimony, the socio-economic benefits were presented to alert the Commission to the socio-economic benefits of the final decision. The Company's announcement on June 9, 2011, and its proposal with this filing were both based upon the least cost alternative.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnas, page 9, says that the Company is planning to make boiler modifications to allow the burning of coal with a sulfur content of 4.5 lbs/mmBtu. Has the cost of these boiler modifications been factored into KPC's analysis?

RESPONSE

The boiler modification cost has been included in this filing.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 10, lines 2 to 22

a. Please describe, in detail, the "current environmental permits" applied to the boiler that "limit the Plant's possible fuel options", and how a new boiler would mitigate those concerns.

b. Please describe, in detail, the "physical limitations of the boiler" that "limit the Plant's possible fuel options."

c. Please provide any analyses performed by or for the Company on the expected life of the existing boiler.

d. Are there other end-of-life or maintenance issues that prevent the current boiler from being utilized in future years up to the expected life of the plant?

e. Please provide the annual price of coal delivered to Big Sandy from 2000 through 2012, inclusive, and the average sulfur content of that coal.

f. Please list KPC's long-term coal contracts, and details of the contracts, including the length of contract, source of coal, heat and sulfur content of the coal, and the expected annual cost (in $/ton, nominal or real [specify]) of the coal over the term of the contract.

RESPONSE

a. KPCo is not proposing a new boiler be installed, only to be modified. Current environmental permits do not limit the boiler"s operation. The testimony was in error in this respect.

b. See response to Staff 1-46 for a general list and discussion of modifications needed to I ncrease fuel flexibility.

c. There is no analysis of the expected life of the existing boiler.

d. There are no end-of-life or maintenance issues that are expected to prevent the boiler from being utilized in future years.

e. See Attachment 1 to this response for the requested information regarding the delivered price of coal for the Big Sandy Plant. Note that the annual delivered price and sulfur content of coal is not yet available for 2012.

f. See Attachment 2 to this response for the requested information regarding KPCo long-term coal contracts effective as of 1-16-2012.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, page 10, lines 18 to 22.

a. Please confirm that if the Company used a 50/50 blend of either NAPP or ILB coals with CAPP coals at Big Sandy Unit 2 the Company would reduce the quantity of Kentucky coal it would purchase for Big Sandy Unit 2 by 50 percent. If Mr. Wohnhas cannot confirm this, please explain why not.

b. Is it the Company's position that if the Company reduces the quantity of Kentucky coal it purchases for Big Sandy Unit 2 by 50 percent it would reduce the direct and indirect economic impact of sales of Kentucky coal to the Big Sandy plant presented by Mr. Wohnhas on page 8, lines 19 to 21, by 50 percent. If no, please explain why not.

RESPONSE

a. Use of a 50/50 blend of either NAPP or ILB coals with CAPP coal would not necessarily reduce the quantity of Kentucky coal that KPCo purchases by 50 percent. In 2011 KPCo purchased roughly 30% of its total coal (CAPP) from sources within Kentucky, with the balance coming from West Virginia. If KPCo moves to a blend of 50/50 NAPP or ILB and CAPP coal, the percentage of CAPP coal from Kentucky could increase or decrease depending on future prices offered to the Company by sources within Kentucky.

   Moreover, Western Kentucky also has sources of high sulfur coal that could potentially be used to increase the amount of Kentucky coal that the plant will consume when going to a 50% blend of NAPP/ILB coal.

b. Kentucky Power does not have a position on this hypothetical. As explained above, a 50/50 blend of either NAPP or ILB coals with CAPP coal would not necessarily reduce its purchases of Kentucky coal by 50%.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Please identify the generally accepted accounting principles that apply to the determination of the time period over which the Company depreciates major capital investments, such as the capital cost of a FGD.

b. Please identify the time period over which the Company would propose to depreciate the cost of the FGD unit according to those generally accepted accounting principles and in the absence of any material risk of future environmental regulations.

c. Please identify cases in which the Public Service Commission of Kentucky has approved a 15 year time period for depreciation of a FGD.

d. Please identify cases in which the Public Service Commission of Kentucky has approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

e. Please identify cases in which the regulatory commissions in other states in which American Electric Power operates have approved a 15 year time period for depreciation of a FGD.

f. Please identify cases in which the which the regulatory commissions in other states in which AEP operates have approved a time period for depreciation shorter than the one consistent with generally accepted accounting principles in order to reduce the risk of stranded investment.

g. Please list the "increased EPA standards" that could cause operation of this unit not to be economically feasible in the future.

h. Please describe how the Company analyzed the risk associated with those "increased EPA standards" in its economic evaluation of resource alternatives.

i. Please explain how the Company would bear a portion of the risk of stranded investment if the Commission approves recovery through the environmental cost recovery surcharge, and describe the percent of the risk the Company would bear.

j. Please explain, with supporting illustrative calculations, how a 15 year depreciation period would reduce the risk of stranded investment that ratepayers will bear if the Commission approves recovery through the environmental cost recovery surcharge.

RESPONSE

a. The Generally Accepted Accounting Principle (GAAP) that applies to the determination of the time period over which the Company depreciates its investment is the matching principle. The matching principle requires that the asset's cost be allocated to depreciation expense over the life of the asset.

FASB 71 states that if a regulator prescribes a period of time to depreciate an asset that is shorter than the useful life of the asset then using the shorter life is consistent with GAAP.

b. The Company is not proposing a period other than the 15 years since is does not believe it is appropriate to assume an absence of any material risk of future environmental regulations. As stated in response to Staff 1-12, the expected life could reach 70 years and thus the depreciation life would be 25 years.

c. The Company is not aware of any cases in which the KPSC approved a 15 year time period for depreciation of a FGD.

d. The Company is not aware of any cases in which the KPSC approved a shorter time period to recover depreciation in order to reduce the risk of stranded investment.

e. The Company is not aware of any other regulatory commission in other states in which American Electric Power operates has approved a 15 year time period for depreciation of a FGD.

f. In Indiana & Michigan's CPCN filing for a scrubber on one of its Rockport Units in Cause No. 43636, they are asking for a 15 year depreciation period. Please see Attachment 1 to this response as the statutory authority to ask for this time frame..

g. The Company does not know what those future increased EPA standards will be at this time.

h. The Company did not attempt to analyze the risk associated with future unknown increased EPA standards.

i. The Company proposes to make the investment to provide service to its customers at the lowest cost and in accordance with federal law. Under these circumstances the Company should not bear any risk of stranded investment.

j. Attachment 2 to this response is an illustrative calculation comparing the depreciation of an asset over 15 years versus 25 years. You will notice that at the end of 15 years the asset being depreciated over 25 years still has $370M of undepreciated plant (net plant). If the Company were to retire that asset in year 15 (before the end of the 25 year depreciation period), the $370M of net plant is stranded investment. If the asset were to be retired prior to 15 years, both scenarios would have stranded investment, but the asset being depreciated over 15 years would have less stranded investment versus the asset being depreciated over 25 years. Thus, the amount at risk subject to stranded investment is much less.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Ranie Wohnhas, pages 14 and 15.

a. Does the Company expect to recover the net plant balance of Big Sandy Unit 2 from ratepayers at whichever point in time Unit 2 is retired? If yes, what is the basis for the Company position?

b. What is the projected net plant balance of Big Sandy Unit 2 as of January 1, 2015?

c. What is the expected salvage value of Big Sandy Unit 2 as of January 1, 2015 and what is the basis for that estimate?

RESPONSE

a. Yes, the Company expects full recovery on all of its investments made at any of its plants.

b. While Kentucky Power's projections of net plant in service are not available by generating unit, they are available at a functional level (e.g. generation, transmission, and distribution). The projected functional net plant balances as of January 1, 2015 are as follows:

KPCo as of 1-1-2015	NP in $000s
Steam Production	273,883
Production GSU's	886
Transmission	316,195
Distribution	507,373
General	23,775
Intangible	1,888
Total Net Plant	1,124,000

c. The last demolition study for Big Sandy was completed in 2005 and estimated salvage value at $250,000. No newer projections have been made at this time.

Please see Attachment 1 for the last demolition study completed for Big Sandy.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Lila Munsey, page 10, lines 5-15.

a. What is the undepreciated plant balance for Big Sandy Unit 1? Please provide the depreciation schedule for all capital investments not fully depreciated for this unit.

b. What is the undepreciated plant balance for Big Sandy Unit 2? Please provide the depreciation schedule for all capital investments not fully depreciated for this unit.

c. Please list the non-environmental capital expenditures incurred by KPC at the Big Sandy 2 unit from 2000-2012, inclusive and provide a description of major capital expenses (projects over $5 million).

d. Please list all non-environmental capital expenditures KPC expects to incur for Big Sandy Unit 2 from 2012 through 2040, the time period for each project's depreciation, and the revenue requirements for each of the capital expenditures.

RESPONSE

a-b. Plant balances are not available by unit, only by plant. The values could be allocated to the 2 units based on their respective MW. The composite depreciation rate for Big Sandy is 3.78%. The undepreciated plant balance, or the net book value, as of December 31, 2011 is as follows:

$548,402,777	Original Cost
$265,921,030	Accumulated Depreciation
$282,481,747	Net Book Value

c. Please see Attachment 1 of this response for the list of non-environmental capital expenditures incurred by KPCo at Big Sandy Unit 2.

d. Please see Attachment 2 of this response for the list of non-environmental capital expenditures KPCo expects to incur for Big Sandy Unit 2 through 2019. No forecasts have been projected past 2019 at this time.

WITNESS: Lila P Munsey

Big Sandy Unit 2 Capital Actuals
Post-Allocated, Includes AFUDC
Non-Environmental Projects

Sum of activity_cost		Year					
Project Type Level 3	Project	2001	2002	2003	2004	2005	Grand Total
Capital Blanket	000001093 No. 23 pulverizer rebuild				45,695		45,695
	000001878 BS PPB 2003 under 200k			1,147,052	2,857,701	1,086,960	5,091,713
	000002257 BSP PPB Bld Repl.U2 2nd RH Rot				538,583	(293,283)	245,300
	000002538 Retube #1 heater			811,373			811,373
	000002894 Primary Air Volum.Meter Equip			2,456			2,456
	000002957 PPB Projects <200K Aug-Dec 02			1,210,371	92,363		1,302,734
	000009909 Expansion joint fabric on SCR				294,066	42,542	336,608
	BSPPB0002 Boiler & Auxiliaries PPB<100k					129,637	129,637
	BSPPB0004 Coal Pulv/ Mills PPB<100k					1,770	1,770
	BSPPB0005 Combustion Turbine PPB<100k					42,753	42,753
	BSPPB0007 Condenser & Aux. PPB<100k					41,819	41,819
	BSPPB0008 Clg Water Facilities PPB<100k					4,975	4,975
	BSPPB0013 Other Costs PPB<$100k					99,427	99,427
	BSPPB0017 Turb Valves & Ctrls PPB<100k					2,352	2,352
	BSPPBOUT2 U 2 PPB Outage <100k					14,974	14,974
	WSBS00131 Bs2 Replace (1) Condensate Cle				43,157		43,157
	WSBS00185 Bs0 Electric Motors - Stator R				24,311		24,311
	WSN103483 Roll Wheel Oil Monitors				23,323		23,323
	WSX107472 Replace U-2 Alterex			209,940	6,181		216,121
	WSX108711 Replace Seal Skirt			771,512	(385,657)		385,856
Capital Blanket Total				**4,152,704**	**3,539,723**	**1,173,925**	**8,866,352**
Capital Stand Alone	000007777 BSP U0 Fuel Oil System Upgrade				843		843
	WSX107535 Replace Second Rh Rotor With S				601,333		601,333
	WSX113857 Replace Big Sandy Unit 2 Rehea			9,876,026	-		9,876,026
	WSX114844 Upgrade Hp Turbine U2		(56,700)	6,360,069	-		6,303,369
Capital Stand Alone Total			**(56,700)**	**16,236,095**	**602,176**		**16,781,571**
#N/A	#N/A	510,995	(502,231)	39,704,247	1,195,776	468,403	41,377,189
#N/A Total		510,995	(502,231)	39,704,247	1,195,776	468,403	41,377,189
Grand Total		510,995	(558,931)	60,093,046	5,337,675	1,642,328	67,025,113

Projects >$5 MM
Project information not available - Cannot determine generating unit or environmental/ non-environmental status

Big Sandy Unit 2 Capital Actuals
Post-Allocated, Includes AFUDC
Non-Environmental Projects

Sum of activity_cost		Year						
Project Type Level 3	Project	2006	2007	2008	2009	2010	2011	Grand Total
Capital Blanket	000001878 BS PPB 2003 under 200k	136,852	100,147		(3,290)	(2,760)		230,949
	000002257 BSP PPB Bld Repl.U2 2nd RH Rot	139,060						139,060
	000009909 Expansion joint fabric on SCR	154						154
	BS0000004 Repl U2 LPRH Attemperator			325,705				325,705
	BSFOCAPU2 Cancelled	2,788	10,557					13,346
	BSPPB0002 Boiler & Auxiliaries PPB<100k	115,613	176,935	413,923	830,128		3,066	1,539,663
	BSPPB0003 Boiler MU Water Supply PPB<100	265,004	317,611	201,455	43,189	9,322	29,224	865,805
	BSPPB0004 Coal Pulv/ Mills PPB<100k	400,698	431,912	28,345	360,937	330,209	482,888	2,034,990
	BSPPB0005 Combustion Turbine PPB<100k	27,833	0					27,833
	BSPPB0006 Comb Turb. Generator PPB<100k	162,582	(5,337)					157,245
	BSPPB0007 Condenser & Aux PPB<100k	(3,220)	21,244	116,089	160,302	34,758	63,224	392,397
	BSPPB0008 Clg Water Facilities PPB<100k	22,748	26,783	61,791	16,438	4,939		132,700
	BSPPB0011 Generator & Support PPB<100k		39,004	5,754		4,740	34,508	84,006
	BSPPB0012 HRSG PPB<100k	14,152		(0)				14,152
	BSPPB0013 Other Costs PPB<$100k	344,175	819,836	156,919	522,029	309,618	339,115	2,491,693
	BSPPB0016 Turb & Support Sys PPB<100k		(0)				202,857	202,857
	BSPPB0017 Turb Valves & Ctrls PPB<100k	-						-
	BSPPBOUT2 U 2 PPB Outage <100k	2,308,390	1,050,721	348,237		240,014	78,780	4,026,142
	BSPPBS018 Upgr Bently TSI EquipPPB>100k		335,638					335,638
	BSPPBS043 BSP U1Acoustic leak detector				147,368	2,517		149,885
	BSPPBS047 Replace Ventilation Fan U2 Pen	161,643						161,643
	BSPPBS050 Rebuild #22 Pulv grinding zone	139,248	(139,248)					-
	BSPPBS051 Rebuild #21pulv grinding zone		565,773				359,828	925,600
	BSPPBS054 Replace #23 pulv gearbox	177,437						177,437
	BSPPBS080 Blr Acoustic Leak Detection U2	377,031	3,857					380,889
	BSPPBS087 Air Htr Exp. Joints-Outlet U2			0				0
	BSPPBS139 Repl BFPT rotor w/spare	265,094						265,094
	BSPPBS140 BFPT overspeed trip/LVDT U2	272,696	(1,272)					271,424
	BSPPBS142 Repl six (6) capacity dampers	137,232	193					137,425
	BSPPBS143 Repl BR vent fans & MCC	474,482	(49,994)					424,487
	BSPPBS148 Rpl ovrspd trip main turbine			231,827	-			231,827
	BSPPBS150 Repl U2 CR annunciator			0				0
	BSPPBS168 PA shutoff dampers repl			0		67,815		67,815
	BSPPBS169 Repl U2 generator rectifiers			349,651				349,651
	BSPPBS176 U2 Ash Hopper Seal Skirt			283,861				283,861
	BSPPBS177 Repl U2 PA fan rotor			97,958				97,958
	BSPPBS178 Repl chemical clng piping U2				220,269			220,269
	BSPPBS179 Upgrade all ovation computers			158,595				158,595
	BSPPBS185 Repl turbine crossover exp jts			182,947	45			182,992
	BSPPBS198 BS2 Repl EJ on SCR duct		239,115			195,515		434,629
	BSPPBS199 BS2 EJ24 inlet duct to air htr		-					-
	BSPPBS200 Air Heater #2 Support Bearings			194,535				194,535
	BSPPBS201 North Booster Fan Blades - Rep			3,650		48,079		51,729
	BSPPBS206 Demineralizer control repl					401,932	1,507	403,439
	BSPPBS210 Air Heater #1support bearings			(0)				(0)
	BSPPBS216 Passenger Elev Upgrade U2				17,966	(17,966)		-
	BSPPBS241 Rep #26 Pulv Grinding Zone Reb				166,297	(166,297)		-
	BSPPBS248 BS2 Rep Softener Tank /Piping						191,706	191,706
	BSPPBS250 BS2 Fire Hdr Vv #79 to #83					65,832	9,655	75,487
	BSPPBS252 BS2 #22 PULV GRINDING ZONE					148,855	7,305	156,160
	BSPPBS253 BS2 MAIN FEED PUMP						0	0
	BSPPBS254 BS2 Pulv #26 Rebuild						397,415	397,415
	BSPPBS255 BS2 Purchase 700 HP Pulv Mtr						(0)	(0)
	BSPPBS261 BS2 N. Sec. Air Exp. Jt (EJ4)						154,639	154,639
	BSPPBS262 BS2 #24 Pulv Grinding Zone Reb						325,711	325,711
	BSPPBS265 BS2 #26 Pulv Grinding Zone Reb						303,695	303,695
	BSPPBS269 BS0 Recirc Overboard Piping						125,956	125,956
	BSTAXCR07 Davis&Burton SCR Tax Credit 07						(104,434)	(104,434)
	WSN102960 Perpetual Rlmnt Adj				65,414			65,414
	WSX108711 Replace Seal Skirt					-		-
Capital Blanket Total		5,941,692	3,943,475	3,161,243	2,547,091	1,677,122	3,006,646	20,277,269
Capital Stand Alone	BS0000036 BS2 MAIN FEED PUMP						521,324	521,324
	BSPPBS235 South MainTurb Oil Cooler U2			515,176	(515,176)			-
	BSU2CI013 BS2 Lwr Furnace Sidewall Rpl			6,003,330	(31,494)			5,971,837
Capital Stand Alone Total				6,518,507	(546,670)		521,324	6,493,161
Grand Total		5,941,692	3,943,475	9,679,750	2,000,421	1,677,122	3,527,971	26,770,430

Projects >$5 MM

Big Sandy Unit 2 Capital Forecast
Post-Allocated, Excludes AFUDC
Non-Environmental Projects

Project Type Level 3	Project	2012 Fore $	2013 Fore $	2014 Fore $	2015 Fore $	2016 Fore $	2017 Fore $	2018 Fore $	2019 Fore $
Capital Blanket	000012594 Replace U2 BFPT with spare	-	-	-	238,194	-	-	-	-
	BS0000027 Upgrade EHC Pumps & Piping U2	-	-	124,004	-	-	-	-	-
	BSPPB0002 Boiler & Auxiliaries PPB<100k	28,674	27,976	20,667	-	205,947	143,690	-	-
	BSPPB0003 Boiler MU Water Supply PPB<100	203,229	26,925	26,867	26,516	231,103	208,957	-	-
	BSPPB0004 Coal Pulv/ Mills PPB<100k	-	-	-	-	69,535	87,710	78,784	-
	BSPPB0007 Condenser & Aux. PPB<100k	-	-	-	-	-	-	335,992	-
	BSPPB0013 Other Costs PPB<$100k	42,555	51,780	-	-	89,987	-	63,723	-
	BSPPBOU26 Capital PPB U2 Outage	-	-	-	-	-	-	-	149,649
	BSPPBOUT2 U 2 PPB Outage <100k	-	-	95,070	188,672	218,832	237,334	645,337	-
	BSPPBS022 Sec Air Exp Jt PPB Out >100k	-	-	-	-	224,967	-	-	-
	BSPPBS051 Rebuild #21pulv grinding zone	-	-	186,006	178,473	194,290	-	220,133	-
	BSPPBS054 Replace #23 pulv gearbox	-	-	-	-	127,822	-	144,824	-
	BSPPBS060 Repl bull gear in #2 air compr	106,906	173,354	106,813	181,533	182,562	-	206,850	-
	BSPPBS062 Inst pulv motors with TEFC	360,537	351,515	62,002	-	-	-	-	-
	BSPPBS066 Upgrade protective relaying	-	-	-	-	85,897	-	-	-
	BSPPBS069 Heat Rate Instrumentation U2	-	-	-	-	79,250	99,964	92,688	-
	BSPPBS085 MCC & VCC Replacement U2	-	-	-	-	-	-	104,273	-
	BSPPBS087 Air Htr Exp. Joints-Outlet U2	123,014	-	124,004	-	122,709	154,783	139,031	-
	BSPPBS117 Repl 2 U2 blr expansion joints	-	-	-	-	306,774	-	-	-
	BSPPBS121 Repl U2 boiler refractory	-	-	-	76,489	-	-	231,719	-
	BSPPBS146 Repl burner exp joints U2	-	-	-	-	102,258	-	115,859	-
	BSPPBS157 BS2 HVAC Battery Room	85,386	-	-	-	-	-	-	-
	BSPPBS177 Repl U2 PA fan rotor	111,398	-	-	-	-	-	-	-
	BSPPBS187 Repl turb crossover exp jts	-	-	175,672	-	-	-	-	-
	BSPPBS196 Reline Feeder Hoppers 13A-D	-	-	-	-	-	-	347,578	-
	BSPPBS215 HP Turb (ADSP) Rep for stock	-	-	258,341	-	-	-	-	-
	BSPPBS217 Boiler Room Roof U2	-	-	-	-	255,645	-	-	-
	BSPPBS219 Turbine Heater Bay Roof U2	-	-	-	-	-	232,175	-	-
	BSPPBS226 Cooling Water Coolers Upgrade	-	-	-	-	265,871	-	-	-
	BSPPBS227 Ovation Control Sys Upgrades	-	-	-	-	122,096	-	-	-
	BSPPBS231 Water Chemistry Sample Room U2	-	-	-	-	230,080	-	-	-
	BSPPBS233 Replace Plant Batteries U2	15,978	-	-	-	-	-	-	-
	BSPPBS244 Retube Hydrogen Coolers U2	-	-	-	-	-	-	1	-
	BSPPBS245 Redundant Steam Packing Exhaus	-	-	-	-	-	-	133,238	-
	BSPPBS256 BS2 SV Vent Stacks 6" Piping	373,203	-	-	-	-	-	-	-
Capital Blanket Total		**1,450,880**	**631,550**	**1,179,446**	**889,877**	**3,115,625**	**1,164,613**	**2,860,031**	**149,649**
Capital Stand Alone	000001292 Economizer Casing Support Stru	-	-	-	8,158,780	-	-	-	-
	000004958 BS2 Replace C W Piping	-	-	-	-	-	-	2,539,430	-
	000004959 BS2 Repl rear wall ash hopper	-	-	-	-	-	-	5,792,969	-
	000014134 BS-Repl Sta 14 switchgear	-	-	-	1,172,825	-	-	-	-
	000014740 Turbine Rotor LP A/B U2	-	-	516,682	-	-	-	-	-
	000014742 BS2 HP R/H & 2nd R/H	-	584,801	-	-	-	-	-	-
	000014778 Replace seal skirt U2	-	-	-	331,450	-	-	-	-
	BS0000006 LPA & B Rotor LSB - Replace	-	-	4,107,625	-	-	-	-	-
	BS0000007 Second RH Rotor Repairs	570,633	553,671	-	-	-	-	-	-
	BS0000015 Lower L&R Sidewall Hdrs & Tubi	-	-	-	-	-	-	2,317,188	-
	BS0000016 Aux Condenser Retube U2	-	-	-	-	-	-	1,390,313	-
	BS0000018 BS1 Replace Manlifts Sta 11,12	-	1,593,100	-	-	-	-	-	-
	BS0000025 Cooling Tower Support Sys U2	-	-	-	-	-	-	1,737,891	-
	BS0000030 Rewedge Generator U2	244,027	-	-	-	-	-	-	-
Capital Stand Alone Total		**814,660**	**2,731,572**	**4,624,307**	**9,663,055**	**-**	**-**	**13,777,791**	**-**
Grand Total		**2,265,540**	**3,363,122**	**5,803,753**	**10,552,932**	**3,115,625**	**1,164,613**	**16,637,822**	**149,649**

Kentucky Power Company

REQUEST

Direct Testimony of Lila Munsey page 12 and Exhibit LPM-2.

a. Please provide all assumptions and workbooks, in electronic format with all calculations operational, used to prepare Exhibit LPM-2.

b. Please re-run the calculations underlying Exhibit LPM-2 using a depreciation rate of 3.52%

c. Please identify the generally accepted accounting principles that were applied to establish a depreciation rate of 3.52% for the other environmental projects in this filing.

RESPONSE

a. Please see the response to Item No. 28 of the Attorney General's first set of data requests in this case for a complete electronic file of the LPM exhibits that were prepared for this case.

b. The electronic files produced in response to Item No. 28 of the Attorney General's first set of data requests in this case may be used to run the requested calculations.

c. The Generally Accepted Accounting Principle (GAAP) that applies to the determination of the time period over which the Company depreciates its investment is the matching principle. The matching principle requires that the asset's cost be allocated to depreciation expense over the life of the asset.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Direct Testimony of Lila Munsey pages 23 and 24 and Exhibit LPM-14.

a. Please provide all assumptions and workbooks, in electronic format with all calculations operational, used to prepare Exhibit LPM-14.

b. Please provide a projection of the effect on residential customers for every year of the 15 year depreciation period. Please provide all supporting assumptions and workbooks, in electronic format with all calculations operational.

c. Please provide a corresponding set of calculations to show the percent increase in annual billed revenues for each tariff to which the Environmental Surcharge is applicable. Please provide all supporting assumptions and workbooks, in electronic format with all calculations operational.

d. Please provide a projection of the effect on residential customers for every year of the 15 year depreciation period. Please provide all supporting assumptions and workbooks, in electronic format with all calculations operational.

RESPONSE

a. Please see the response to Item No. 28 of the Attorney General's first set of data requests in this case for a complete electronic file of the LPM exhibits that were prepared for this case, which may be used to run the requested calculations.

b-d. The Company has not performed the requested calculations.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Direct Testimony of McManus, page 8. Please provide a fully copy of the NSR Consent Decree pertaining to the Big Sandy Unit.

RESPONSE

Please refer to the response provided by the Company in the Kentucky Commission Staff's First Request for Information, No. 3(b).

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Direct Testimony of McManus, pages. 11-12, notes that the operation of Big Sandy Units 1 and 2 will need to be constrained in order to comply with the 2012 CSAPR requirements. Did KPC or AEP consider the option of retiring Big Sandy 1 in 2012 rather than waiting until 2015 in order to help satisfy the 2012 CSAPR requirements? Did KPC or AEP evaluate? Should they have?

RESPONSE

A retirement of Big Sandy Unit 1 in 2012 in order to help satisfy the 2012 CSAPR requirements, in lieu of the approach described by Company witness McManus, was not evaluated because the allowance-based approach of CSAPR provides some compliance flexibility and does not require a drastic step like full retirement. This view was further supported by the EPA's proposed revisions to CSAPR which included a delay in the start of the (allowance) Assurance Provision restriction until the year 2014, thereby making the prospect of acquiring and utilizing such allowance purchases to help achieve the Rule's budget requirements prior to 2014 even more tenable.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Direct Testimony of McManus, bullet point 3 on page 16 regarding GHG Legislation.

a. Does the Company anticipate that the Big Sandy 2 unit would be subject to the EPA's GHG Tailoring Rule?

b. If so, when? What impact does the Company anticipate the Tailoring Rule having on either the costs or operations of the Big Sandy 2 unit?

c. If not, why not?

RESPONSE

a. The Company does not anticipate at this time that Big Sandy Unit 2 will become subject to EPA's GHG Tailoring Rule.

b. N/A

c. Big Sandy Unit 2 could become subject to the Tailoring Rule if it undergoes a major modification that results in an increase in GHG emissions greater than the threshold level established in the Rule. The Company does not anticipate that occurring at this time.

WITNESS: John M McManus

Kentucky Power Company

REQUEST

Direct Testimony of McManus page 22 lines 8-10 regarding "FGD (Hg) Waste Water Treatment system installation" at the Amos Plant and Exhibit JMM-1 with description of Applicable Environmental Program with CWA NPDES.

a. Please provide the current NPDES permit for Big Sandy 2.

b. If applicable, please provide any of the Company's recent applications for changes or modifications to the NPDES permit for Big Sandy 2.

c. Does the Company anticipate that the pending Effluent Limitation guidelines rule could impact Big Sandy 2?

d. If so, what would be the expected cost of this rulemaking. If not, why?

e. Has a cost for the pending Effluent Limitation guidelines been taken into account modeling the cost efficacy of Big Sandy 2? If not, how would such a cost impact this analysis?

RESPONSE

a. Please see Sierra Club Set 1-25 Attachment 1 for the current NPDES permit for Big Sandy Unit 2.

b. Please see Sierra Club Set 1-25 Attachment 2 for the Company's most recent application for modifications to the NPDES permit for Big Sandy Unit 2.

c. Yes, the pending Effluent Limitation guidelines rule will apply to Big Sandy Unit 2 as these guidelines apply to all steam electric generating plants in the U.S.

d. The cost efficacy modeling for Big Sandy Unit 2 does include a very high-level estimate to provide for installation of a waste water treatment plant as part of the overall compliance strategy being driven by EPA rulemakings, including the Effluent Guidelines. Please refer to the response for KPSC Staff 1-47. However, the Effluent Limitation Guidelines Rule is not expected to be issued in proposed form until July, 2012 and so we have had to make assumptions regarding the design of that system that may be significantly changed as the rulemaking progresses.

e. Please see the response to item d.

WITNESS: John M McManus

KPDES

KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

PERMIT

PERMIT NO.: KY0000221

AUTHORIZATION TO DISCHARGE UNDER THE KENTUCKY POLLUTANT DISCHARGE ELIMINATION SYSTEM

Pursuant to Authority in KRS 224,

Kentucky Power Company
1 Riverside Plaza
Columbus, Ohio 43215-2373

is authorized to discharge from a facility located at

Kentucky Power Company
Big Sandy Plant
U.S. Highway 23
Louisa, Lawrence County, Kentucky

to receiving waters named

Outfalls 001 and 018 are to Blaine Creek at milepoints 2.0 and 1.9, respectively.
Outfalls 002, 003, and 005 are to Outfall 001 via the bottom ash pond.
Outfalls 004, 007 through 017, and 019 are to the Big Sandy River between milepoints 19.6 and 20.45.
Outfall 006 is the plant intake.

in accordance with effluent limitations, monitoring requirements, and other conditions set forth in PARTS I, II, III, IV, and V hereof. The permit consists of this cover sheet and PART I 8 pages, PART II 1 page, PART III 1 page, PART IV 3 pages, and PART V 3 pages.

This permit shall become effective on APR 1 2003

This permit and the authorization to discharge shall expire at midnight, March 31, 2006.

FEB 4 2003
Date Signed

Jeffrey W. Pratt, Director
Division of Water

Robert W. Logan
Commissioner

DEPARTMENT FOR ENVIRONMENTAL PROTECTION
Division of Water, Frankfort Office Park, 14 Reilly Road, Frankfort, Kentucky 40601

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A1. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 001 - Combined wastewaters of fly ash pond overflow (ash transport waters, coal pile runoff and bottom ash pond overflow consisting of low volume wastes, sump waters, storm water runoff, metal cleaning wastes (Outfall 005), and cooling tower blowdown (Outfalls 002 and 003)).

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	2/Month	Instantaneous
Total Suspended Solids (mg/l)	30	60	2/Month	Grab
Oil & Grease (mg/l)	6.0	6.0	2/Month	Grab
Hardness (as mg/l)($CaCO_3$)	Report	Report	2/Month	Grab
Total Recoverable Metals (mg/l)	Report	Report	1/Quarter	Grab
Chronic Toxicity (TU_c)	N/A	2.12	1/Quarter	3 Grabs

The pH of the effluent shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored 2/Month by grab sample.

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

The abbreviation N/A means Not Applicable.

The effluent characteristic "Total Recoverable Metals" means Antimony, Arsenic, Beryllium, Cadmium, Chromium, Copper, Lead, Mercury, Nickel, Selenium, Silver, Thallium, and Zinc. To report the results of the analyses for this parameter, the permittee shall total the results of the analyses for each individual parameter, and report that aggregate value on the DMR. The laboratory bench sheets showing the results for each parameter shall be attached to the DMR.

A2. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 002 - Unit 1 cooling tower blowdown. Outfall 002 is an internal outfall discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Calculated
Free Available Chlorine (mg/l)	0.2	0.5	Occurrence	Multiple Grab
Total Residual Chlorine (mg/l)	0.2	0.2	Occurrence	Multiple Grab
Total Residual Oxidants (mg/l)	Report	0.2	Occurrence	Multiple Grab
Time of Oxidant Addition (Minutes/unit/day)	N/A	120	Occurrence	Log
Total Chromium (mg/l)	0.2	0.2	Annually	Grab
Total Zinc (mg/l)	1.0	1.0	Annually	Grab
Priority Pollutants (mg/l)	Report	NDA	Annually	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

Priority Pollutants shall be monitored annually by grab sample or by engineering calculations. The results of the analyses/engineering calculations shall be totaled and reported as a single concentration on the DMR. The laboratory bench sheets/engineering calculations showing the results for each pollutant shall be attached to the DMR. The term Priority Pollutants means the 126 priority pollutants listed in 40 CFR Part 423 Appendix A. See Attachment A - Fact Sheet Addendum for Steam Electric Power Generating Plants.

The term Total Residual Oxidants (TRO) means the value obtained using the amperometric titration or DPD methods for total residual chlorine described in 40 CFR Part 136. In the event of addition of an oxidant other than chlorine, the permittee shall receive prior approval from the Division of Water permitting staff before the initial use.

The measurement frequency "Occurrence" means during periods of chlorination or oxidant addition, but no more frequent than once per week.

The sample type "Multiple Grab" means grab samples collected at the approximate beginning of oxidant discharge and once every fifteen (15) minutes thereafter until the end of oxidant discharge.

The abbreviation N/A means Not Applicable.

The abbreviation NDA means No Detectable Amount.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 003 - Unit 2 cooling tower blowdown. Outfall 003 is an internal outfall that discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Calculated
Free Available Chlorine (mg/l)	0.2	0.5	Occurrence	Multiple Grab
Total Residual Chlorine (mg/l)	0.2	0.2	Occurrence	Multiple Grab
Total Residual Oxidants (mg/l)	Report	0.2	Occurrence	Multiple Grab
Time of Oxidant Addition (Minutes/unit/day)	N/A	120	Occurrence	Log
Total Chromium (mg/l)	0.2	0.2	Annually	Grab
Total Zinc (mg/l)	1.0	1.0	Annually	Grab
Priority Pollutants (mg/l)	Report	NDA	Annually	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

Priority Pollutants shall be monitored annually by grab sample or by engineering calculations. The results of the analyses/engineering calculations shall be totaled and reported as a single concentration on the DMR. The laboratory bench sheets/engineering calculations showing the results for each pollutant shall be attached to the DMR. The term Priority Pollutants means the 126 priority pollutants listed in 40 CFR Part 423 Appendix A. See Attachment A - Fact Sheet Addendum for Steam Electric Power Generating Plants.

The term Total Residual Oxidants (TRO) means the value obtained using the amperometric titration or DPD methods for total residual chlorine described in 40 CFR Part 136. In the event of addition of an oxidant other than chlorine, the permittee shall receive prior approval from the Division of Water permitting staff before the initial use.

The measurement frequency "Occurrence" means during periods of chlorination or oxidant addition, but no more frequent than once per week.

The sample type "Multiple Grab" means grab samples collected at the approximate beginning of oxidant discharge and once every fifteen (15) minutes thereafter until the end of oxidant discharge.

The abbreviation N/A means Not Applicable.

The abbreviation NDA means No Detectable Amount.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 004 - Sanitary wastewater.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Month	Instantaneous
Biochemical Oxygen Demand, 5-day (mg/l)	30	45	1/Month	Grab
Total Suspended Solids (mg/l)	30	45	1/Month	Grab
Ammonia (as N) (mg/l)	20	30	1/Month	Grab
Fecal Coliform Bacteria (#/100 ml)	200	400	1/Month	Grab
Dissolved Oxygen (minimum) (mg/l)	2.0	N/A	1/Month	Grab
Total Residual Chlorine (mg/l)	0.019	0.019	1/Month	Grab

The pH of the effluent shall not be less than 6.0 standard units nor greater than 9.0 standard units and shall be monitored 1/Month by grab sample.

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest accessible point after final treatment, but prior to actual discharge to or mixing with the receiving waters or wastestreams from other outfalls.

The abbreviation N/A means Not Applicable.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 005 - Metal cleaning wastes. Outfall 005 is an internal outfall that discharges to Outfall 001.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Batch	Calculated
Total Copper	1.0 mg/l	1.0 mg/l	1/Batch	Grab
Total Iron	1.0 mg/l	1.0 mg/l	1/Batch	Grab

The pH of the effluent shall be monitored 1/Batch by grab sample.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: nearest point prior to commingling with the waters of either ash pond.

Metal cleaning waste shall mean any wastewater resulting from cleaning (with or without chemical cleaning compounds) any metal process equipment including, but not limited to, boiler tube cleaning, boiler fireside cleaning, and air preheater cleaning. In accordance with the conditions of the previous permits, the permittee is allowed to discharge air preheater wash waters and boiler fireside cleaning directly to the ash pond without limitations or monitoring requirements, pursuant to the Jordan Memorandum. Monitoring is required only when chemical metal cleaning activities are being performed.

A3. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: 006 - Plant intake.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type
Flow (MGD)	Report	Report	1/Week	Instantaneous
Temperature (°F)	Report	Report	1/Week	Grab
Total Suspended Solids (mg/l)	Report	Report	1/Week	Grab
Hardness (as mg/l) ($CaCO_3$)	Report	Report	1/Week	Grab
pH (Standard Units)	Report	Report	1/Week	Grab
Total Recoverable Metals	N/A	Report	1/Quarter	Grab

There shall be no discharge of floating solids or visible foam or sheen in other than trace amounts.

Samples taken in compliance with the monitoring requirements specified above shall be taken at the following location: plant intake, except that temperature may be monitored at the river pumps.

The effluent characteristic "Total Recoverable Metals" means Antimony, Arsenic, Beryllium, Cadmium, Chromium, Copper, Lead, Mercury, Nickel, Selenium, Silver, Thallium, and Zinc. To report the results of the analyses for this parameter, the permittee shall total the results of the analyses for each individual parameter and report that aggregate value on the DMR. The laboratory bench sheets showing the results for each parameter shall be attached to the DMR.

A4. EFFLUENT LIMITATIONS AND MONITORING REQUIREMENTS

During the period beginning on the effective date of this permit and lasting through the term of this permit, the permittee is authorized to discharge from Outfall serial number: **Outfall 007** - Storm water runoff from 91.8 acres north of U.S. Highway 23, the area north of Unit 2, and the area around the performance building and behind the storage warehouses. Additional wastewaters include occasional fire header flushing, Unit 1 cooling tower emergency overflow and cooling waters and auxiliary blowdown during Unit 2 outage, **Outfall 008** - Storm water runoff from 5.7 acres west of Unit 2 coal storage area and Unit 2 turbine roof drains. Additional wastewaters include Unit 2 condensate storage tank overflow, Unit 2 wastewater sump overflow, south Unit 2 coal pile drainage pond sump overflow, occasional fire header flushing and Unit 2 cooling tower emergency overflow, **Outfall 009** - Storm water runoff from 104.3 acres north of U.S. Highway 23 and north of Unit 2 coal storage area, **Outfall 010** - Storm water runoff from 0.8 acres east of Unit 2 coal yard buildings, **Outfall 011** - Storm water runoff from coal yard building roof drains and 1.3 acres south of Unit 2 coal yard buildings, **Outfall 012** - Has been eliminated by rerouting to coal pile runoff ponds, **Outfall 013** - Storm water runoff from 0.4 acres south of Unit 2 cooling tower, **Outfall 014** - Storm water runoff from 2.0 acres west of Unit 2 cooling tower, **Outfall 015** - Storm water runoff from 1.7 acres around storeroom warehouses, parking lot and roof drains, **Outfall 016** - Storm water runoff from 0.7 acres around Unit 1 condensate storage tank and road. Additional wastewaters include Unit 1 condensate storage tank overflow, Unit 1 cooling tower basin drain, and tower flume overflow, **Outfall 017** - Storm water runoff from 38.8 acres north of U.S. Highway 23 around bottom ash ponds and parking lot, Unit 1 service building, coal storage area, tractor sheds, and roof drains, **Outfall 018** - Interior drains of the fly ash dam. May include overflow of mine seepage sump if sump pump fails, and **Outfall 019** - Storm water runoff from 1.5 acres east of Unit 1 cooling tower.

Such discharges shall be limited and monitored by the permittee as specified below:

EFFLUENT CHARACTERISTICS	DISCHARGE LIMITATIONS		MONITORING REQUIREMENTS	
	Monthly Avg.	Daily Max.	Measurement Frequency	Sample Type

The Division of Water has determined that implementation of Best Management Practices (BMPs) would be the most effective approach for controlling pollutants from these areas.

B. Schedule of Compliance

The permittee shall achieve compliance with all requirements on the effective date of this permit.

C. Cooling Water Additives, FIFRA, and Mollusk Control

The discharge of any product registered under the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA) in cooling water which ultimately may be released to the waters of the Commonwealth is prohibited, except Herbicides, unless specifically identified and authorized by the KPDES permit. In the event the permittee needs to use a biocide or chemical not previously reported for mollusk control or other purpose the permittee shall submit sufficient information, a minimum of thirty (30) days prior to the commencement of use of said biocides or chemicals, to the Division of Water for review and establishment of appropriate control parameters. Such information requirements shall include:

1. Name and general composition of biocide or chemical,
2. Any and all aquatic organism toxicity data,
3. Quantities to be used,
4. Frequencies of use,
5. Proposed discharge concentrations, and
6. EPA registration number, if applicable.

D. Polychlorinated Biphenyls

Pursuant to the requirements of 401 KAR 5:065, Section 4(4) (40 CFR Parts 423.12(b)(2) and 423.13(a)), there shall be no discharge from any point source of polychlorinated biphenyl compounds such as those commonly used in transformer fluids. The permittee shall implement this requirement as a specific section of the BMP plan developed for this station.

E. Selective Catalytic Reduction Devices or Systems (SCRs) and Nonselective Catalytic Reduction Devices or Systems (NSCRs)

In response to recent Clean Air Act amendments, the installation of these devices for NOx reduction may become necessary. Associated with the installation and operation of these units, an "ammonia slip" may occur resulting in the discharge of ammonia to the ash pond. The impact of such an occurrence on the performance of the ash pond and any eventual impact on the environment is not known. Therefore, should it become necessary to install these devices, the permittee shall develop and implement an Ammonia Monitoring Plan. The plan shall be submitted to the Division of Water within ninety (90) days of the determination that these devices will be installed, and shall include at a minimum influent and effluent monitoring of each unit on a monthly basis with submission of the data as a quarterly report.

F. Section 311, Clean Water Act Exclusion

The permittee is relieved of the reporting and liability requirements under Section 311 of the Clean Water Act for the following substances, consistent with Exclusion 2, authorized by Section 311(a)(a)(B) and 40 CFR Part 117.12 for: Ammonium Hydroxide, Sodium Hypochlorite, Ethylene Diaminetetracetic Acid (EDTA), Sodium Hydroxide, Sodium Nitrite, Sodium Phosphate (Dibasic), and Sulfuric Acid.

STANDARD CONDITIONS FOR KPDES PERMIT

The permittee is also advised that all KPDES permit conditions in KPDES Regulation 401 KAR 5:065, Section 1 will apply to all discharges authorized by this permit.

This permit has been issued under the provisions of KRS Chapter 224 and regulations promulgated pursuant thereto. Issuance of this permit does not relieve the permittee from the responsibility of obtaining any other permits or licenses required by this Cabinet and other state, federal, and local agencies.

It is the responsibility of the permittee to demonstrate compliance with permit parameter limitations by utilization of sufficiently sensitive analytical methods.

PART III

OTHER REQUIREMENTS

A. Reporting of Monitoring Results

Monitoring results obtained during each month must be reported on a preprinted Discharge Monitoring Report (DMR) Form, which will be mailed to you. Each month's completed DMR must be sent to the Division of Water at the address listed below (with a copy to the appropriate Regional Office) postmarked no later than the 28th day of the month following the month for which monitoring results were obtained.

Division of Water
Morehead Regional Office
200 Christy Creek Road, Suite 2
Morehead, Kentucky 40351
ATTN: Supervisor

Kentucky Natural Resources and
Environmental Protection Cabinet
Dept. for Environmental Protection
Division of Water/KPDES Branch
14 Reilly Road, Frankfort Office Park
Frankfort, Kentucky 40601

B. Reopener Clause

This permit shall be modified, or alternatively revoked and reissued, to comply with any applicable effluent standard or limitation issued or approved under 401 KAR 5:050 through 5:080, if the effluent standard or limitation so issued or approved:

1. Contains different conditions or is otherwise more stringent than any effluent limitation in the permit; or

2. Controls any pollutant not limited in the permit.

The permit as modified or reissued under this paragraph shall also contain any other requirements of KRS Chapter 224 when applicable.

PART IV
CHRONIC CONCERNS
Biomonitoring

In accordance with PART I of this permit, the permittee shall initiate the series of tests described below within 30 days of the effective date of this permit to evaluate wastewater toxicity of the discharge from Outfall 001. If the permittee is using a more sensitive species, the initial four (4) tests shall be conducted using both test species as indicated below to provide confirmation of previously identified most sensitive test organism.

1. Test Requirements

A. The permittee shall perform one (1) short-term fathead minnow (*Pimephales promelas*) growth test and one (1) short-term daphnid (*Ceriodaphnia* sp.) life-cycle test. Tests shall be conducted with appropriate replicates of 47% effluent, a control, and a minimum of four (4) evenly spaced effluent concentrations. If the permit limit is less than 100% effluent and greater than or equal to 75% effluent, then one (1) concentration should be 100%. If the permit limit is less than 75% effluent, the permit limit concentration shall be bracketed with two (2) concentrations above and two (2) concentrations below. The selection of the effluent concentrations is subject to revision by the Division. Controls shall be tested concurrently with effluent testing using a synthetic water. The analysis will be deemed reasonable and good only if the minimum control requirements are met (i.e.≥80% survival; 60% adults with 3 broods and 15 young/female for the *Ceriodaphnia* test; an average 0.25 mg weight for the minnow growth test). Any test that does not meet the control acceptability criteria shall be repeated as soon as practicable within the monitoring period (i.e. monthly or quarterly). Noncompliance with the toxicity limit will be demonstrated if the IC_{25} (inhibition concentration) for reproduction or growth is less than 47% effluent. The average reproduction for *Ceriodaphnia* shall be calculated by dividing the total number of live *Ceriodaphnia* young in each concentration by the total number of organisms used to initiate that concentration; the average growth for the fathead minnows shall be calculated by dividing the total weight of surviving minnow larvae in each replicate by the total number of organisms used to initiate that replicate.

B. Tests shall be conducted quarterly or at a frequency to be determined by the permitting authority.

A minimum of three (3) Grab samples will be collected at a frequency of one (1) sample every other day, or at a frequency to be determined by the permitting authority. For example, the first sample would be used for test initiation, day 1, and for test solution renewal on day 2. The second sample would be used for test solution renewal on days 3 and 4. The third sample would be used for test solution renewal on days 5, 6, and 7. The lapsed time from collection of the last aliquot of the composite and its first use for test initiation, or for test solution renewal shall not exceed 36 hours. Grab samples shall be iced during collection and maintained at 4° C until used.

After the first four (4) tests with both species, upon written request to the Division of Water's Bioassay Section, subsequent testing may be performed using only the most sensitive species.

2. Reporting Requirements

Results of all tests conducted with any organism shall be reported according to the most recent format provided by the Division of Water. Test results shall be submitted to the Division of Water with the next regularly scheduled discharge monitoring report.

Due to administrative and regulatory constraints regarding the requirements of Section 3 of this Part, monthly DMRs shall be submitted. Those required to conduct tests on a frequency other than monthly shall submit DMRs with "Not required this monitoring period" typed or written in the parameter row in addition to the DMR reporting the results of the test. All DMRs for Biomonitoring shall be submitted monthly regardless of required monitoring frequency.

3. Chronic Toxicity

A. If noncompliance with the toxicity limit occurs (IC_{25} for reproduction or growth is less than 47% effluent), the permittee must conduct a second test within 15 days of the first failure. This test will be used in evaluating the persistence of the toxic event and the possible need for a Toxicity Reduction Evaluation (TRE).

If the second test demonstrates noncompliance with the toxicity limit, the permittee will be required to perform either of the options listed below. The Division must be notified of the option selected within five (5) days of the failure of this second test.

1) Accelerated Testing

Complete four (4) tests within 90 days of selection of this option to evaluate the frequency and degree of toxicity. The results of the two (2) tests specified in Section 3.A and of the four (4) additional tests will be used for purposes of this evaluation.

If results from two (2) of any six (6) tests show a significant non-compliance with the chronic limit ($\geq$1.2 times the TU_c), or results from four (4) of any six (6) tests show chronic toxicity (as defined in 1.A), a Toxicity Reduction Evaluation (TRE) will be required. The Division reserves the right to require a TRE in situations of recurring toxicity.

2) Toxicity Reduction Evaluation (TRE)

If it is determined that a TRE is required, a plan and implementation schedule must be submitted to the Division within 30 days of notification. The TRE shall include appropriate measures such as in-plant controls, additional wastewater treatment, or changes in the operation of the wastewater discharge to meet permit conditions. The TRE protocol shall follow that outlined in the most recent edition of EPA's guidance for conducting TREs.

B. If a violation of the toxicity limit occurs, different or more stringent monitoring requirements may be imposed in lieu of the normal requirements of this permit for whatever period of time is specified by the Division of Water. The Division reserves the right to require additional testing or a TRE in situations of recurring toxicity.

4. Test Methods

All test organisms, procedures and quality assurance criteria used shall be in accordance with Short-term Methods for Estimating the Chronic Toxicity of Effluents and Receiving Waters to Freshwater Organisms (Third Edition), EPA-600-4-91-002, or the most recent edition of this publication.

PART V

BEST MANAGEMENT PRACTICES

SECTION A. GENERAL CONDITIONS

1. Applicability

These conditions apply to all permittees who use, manufacture, store, handle, or discharge any pollutant listed as: (1) toxic under Section 307(a)(1) of the Clean Water Act; (2) oil, as defined in Section 311(a)(1) of the Act; (3) any pollutant listed as hazardous under Section 311 of the Act; or (4) is defined as a pollutant pursuant to KRS 224.01-010(35) and who have ancillary manufacturing operations which could result in (1) the release of a hazardous substance, pollutant, or contaminant, or (2) an environmental emergency, as defined in KRS 224.01-400, as amended, or any regulation promulgated pursuant thereto (hereinafter, the "BMP pollutants"). These operations include material storage areas; plant site runoff; in-plant transfer, process and material handling areas; loading and unloading operations, and sludge and waste disposal areas.

2. BMP Plan

The permittee shall develop and implement a Best Management Practices (BMP) plan consistent with 401 KAR 5:065, Section 2(10) pursuant to KRS 224.70-110, which prevents or minimizes the potential for the release of "BMP pollutants" from ancillary activities through plant site runoff; spillage or leaks, sludge or waste disposal; or drainage from raw material storage. A Best Management Practices (BMP) plan will be prepared by the permittee unless the permittee can demonstrate through the submission of a BMP outline that the elements and intent of the BMP have been fulfilled through the use of existing plans such as the Spill Prevention Control and Countermeasure (SPCC) plans, contingency plans, and other applicable documents.

3. Implementation

If this is the first time for the BMP requirement, then the plan shall be developed and submitted to the Division of Water within 90 days of the effective date of the permit. Implementation shall be within 180 days of that submission. For permit renewals the plan in effect at the time of permit reissuance shall remain in effect. Modifications to the plan as a result of ineffectiveness or plan changes to the facility shall be submitted to the Division of Water and implemented as soon as possible.

4. General Requirements

The BMP plan shall:

a. Be documented in narrative form, and shall include any necessary plot plans, drawings, or maps.

b. Establish specific objectives for the control of toxic and hazardous pollutants.

   (1) Each facility component or system shall be examined for its potential for causing a release of "BMP pollutants" due to equipment failure, improper operation, natural phenomena such as rain or snowfall, etc.

(2) Where experience indicates a reasonable potential for equipment failure (e.g., a tank overflow or leakage), natural condition (e.g., precipitation), or other circumstances which could result in a release of "BMP pollutants," the plan should include a prediction of the direction, rate of flow, and total quantity of the pollutants which could be released from the facility as result of each condition or circumstance.

c. Establish specific Best Management Practices to meet the objectives identified under paragraph b of this section, addressing each component or system capable of causing a release of "BMP pollutants."

d. Include any special conditions established in part b of this section.

e. Be reviewed by plant engineering staff and the plant manager.

5. Specific Requirements

The plan shall be consistent with the general guidance contained in the publication entitled "NPDES Best Management Practices Guidance Document," and shall include the following baseline BMPs as a minimum.

a. BMP Committee
b. Reporting of BMP Incidents
c. Risk Identification and Assessment
d. Employee Training
e. Inspections and Records
f. Preventive Maintenance
g. Good Housekeeping
h. Materials Compatibility
i. Security
j. Materials Inventory

6. SPCC Plans

The BMP plan may reflect requirements for Spill Prevention Control and Countermeasure (SPCC) plans under Section 311 of the Act and 40 CFR Part 151, and may incorporate any part of such plans into the BMP plan by reference.

7. Hazardous Waste Management

The permittee shall assure the proper management of solid and hazardous waste in accordance with the regulations promulgated under the Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1978 (RCRA) (40 U.S.C. 6901 et seq.) Management practices required under RCRA regulations shall be referenced in the BMP plan.

8. Documentation

The permittee shall maintain a description of the BMP plan at the facility and shall make the plan available upon request to NREPC personnel. Initial copies and modifications thereof shall be sent to the following addresses when required by Section 3:

Division of Water
Morehead Regional Office
200 Christy Creek Road, Suite 2
Morehead, Kentucky 40351
ATTN: Supervisor

Kentucky Natural Resources and
Environmental Protection Cabinet
Dept. for Environmental Protection
Division of Water/KPDES Branch
14 Reilly Road, Frankfort Office Park
Frankfort, Kentucky 40601

9. BMP Plan Modification

The permittee shall amend the BMP plan whenever there is a change in the facility or change in the operation of the facility which materially increases the potential for the ancillary activities to result in the release of "BMP pollutants."

10. Modification for Ineffectiveness

If the BMP plan proves to be ineffective in achieving the general objective of preventing the release of "BMP pollutants," then the specific objectives and requirements under paragraphs b and c of Section 4, the permit, and/or the BMP plan shall be subject to modification to incorporate revised BMP requirements. If at any time following the issuance of this permit the BMP plan is found to be inadequate pursuant to a state or federal site inspection or plan review, the plan shall be modified to incorporate such changes necessary to resolve the concerns.

SECTION B. SPECIFIC CONDITIONS

Periodically Discharged Wastewaters Not Specifically Covered by Effluent Conditions

The permittee shall include in this BMP plan procedures and controls necessary for the handling of periodically discharged wastewaters such as intake screen backwash, meter calibration, fire protection, hydrostatic testing water, water associated with demolition projects, etc.

Kentucky Power Company

REQUEST

Direct Testimony of McManus, Exhibit JMM-1. Tanners Creek Units 1-3. Please describe the SNCR project at TC1-3 and describe in detail why the installation of the SNCR is responsive to CAIR, rather than current regulations.

RESPONSE

See "Sierra Club Set 1-26 Attachment 1" for an overview of the SNCR project at TC1-3.

At the time the SNCR systems were installed and placed in service at Tanners Creek Units 1-3, the CAIR was the applicable EPA environmental regulation to meet fleet NOx emissions, in addition to the New Source Review Consent Decree. The CAIR still remains in effect given the CSAPR stay.

The installation of the Tanners Creek Units 1-3 SNCRs was approved by the Indiana Utility Regulatory Commission in Cause No. 43636 in July 2009.

WITNESS: John M McManus

AMERICAN ELECTRIC POWER

Technical Report Cover Sheet

Unique Document ID: AEP-SNCR-041908

Organizations: AEP Engineering Services Air Emissions Control Equipment Engineering Section

Title: Selective Non-Catalytic Reduction Systems Process Description

Revision: 1

Approvals	Revision 0	Revision 1
Prepared by: J. B. Silk	JBS 4-24-08	JBS 6-2-08
Reviewed by: J. C. Sustar	JCS 4-24-08	JCS 6/5/08
Approved by: D. H. Drew	DHD 4-25-08	DHD 6/5/08

Revision Index

Date	Revision No.	Description
4/25/08	0	Initial Release
6/2/08	1	1. Clarifications to the General System Description
		2. Design Clarifications to Clinch River System SNCR, Appendix B.
		3. Additional Information for Sporn Units 3 and 4 SNCR System, Appendix D.

AEP Selective Non-Catalytic Reduction System Process Description

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2.0	AEP SNCR System General Design Basis	2
3.0	SO_3 FGC System Process Overview	5
4.0	AEP SO_3 FGC System General Design Basis	7
5.0	Urea Reference Information	9

Appendix- AEP Unit Location SNCR System Designs

A. Big Sandy Plant Unit 1

B. Clinch River Plant Units 1, 2, 3

C. Kanawha Plant River Unit 1

D. Sporn Plant Units 3, 4

E. Tanners Creek Plant Units 1, 2, 3, 4

Illustrative Figures

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Figure 2	AEP SNCR System Control Equipment Configuration	6

AEP Selective Non-Catalytic Reduction System Process Description

References

1. Steam, It's Generation & Use, Babcock & Wilcox, 40th edition, Chapter 34, section on Selective Non-Catalytic Reduction Technology

2. AEP Cardinal Unit 1 Selective Non-Catalytic Reduction (SNCR) Demonstration Test Program, EPRI Product ID# 1000154, July 2000

AEP Selective Non-Catalytic Reduction System Process Description

1.0 SNCR Process Overview

Selective Non-Catalytic Reduction (SNCR) is an environmental control technology applied to coal fired boiler furnaces to reduce the nitrogen-oxygen (NOx) compound products of combustion in order to minimize the concentration of NOx in the flue gas emission. The SNCR process involves injection of ammonia or the ammonia-based compound, urea into the gas produced from the boiler's fuel combustion. The injection agents react selectively with NOx forming primarily nitrogen gas (N_2) and water (H_2O). In addition to N_2 and water, nitrous oxide (NO_2) formation will be a minor product of the reaction. The excess or unreacted ammonia is called ammonia slip and is undesirable.

The SNCR reactions occur over a relatively narrow temperature range of 1600 °F and 2100 °F (870 °C and 1150 °C). At the low temperature side of the window, the injected agent will not react and the ammonia slip will be high. On the high temperature side of the window, the agent reactions cease to be selective. In this case, the injected agents begin to react with O_2, forming additional NOx. The challenge of an SNCR system application is locating the furnace treatment zone at all unit operating loads. The primary design factors of an SNCR system include: the initial or baseline NOx level, the carbon monoxide concentration at the point of injection, and residence time.

The selective non-catalytic reduction is typically performed in the furnace where relatively high temperatures serve to initiate the breakdown of urea or ammonia to form the transient species which lead to effective NOx reduction. The technology is limited to high temperature zones which ensure very low ammonia slip levels. At very high furnace temperatures, however, performance can be lessened by competing reactions which either consume effective chemical or lead to NOx formation. Therefore, the apparent limitations of SNCR technology in certain applications such as reduction efficiency and chemical usage are eliminated by arranging for a downstream ammonia slip control device to allow the SNCR to operate in cooler regions where NOx reaction is increased and chemical usage is reduced.

The SNCR process uses either an anhydrous or aqueous **ammonia** (NH_3) solution *or* the ammonia-based, aqueous solution- **urea** $[(NH_2)_2CO + H_2O]$. The urea technology requires longer residence time to achieve the necessary chemical reactions due to the additional time required to vaporize the liquid droplets. However, due to the hazards of storing and handling NH_3, it has become more practical to use urea for the SNCR process which can be received as a solution mixed at a certain concentration or as a solid and then mixed with water and stored as a solution.

While thermally generated NOx compounds form above 2200 °F which is above the effective range of an SNCR application, 80% of the NOx formation from fossil fuel combustion is formed from fuel bound nitrogen. Since the SNCR process attacks the NOx generated within the fuel combustion products, the SNCR becomes a viable NOx reduction technology for subcritical units. The resulting product of the SNCR process injection chemical agent is elemental nitrogen (N_2), carbon dioxide (CO_2), and water

(H_2O).The NOx reduction process for both types of SNCR chemical agents are as follows:

Ammonia: $4NO + 4NH_3 + O_2 \longrightarrow 4N_2 + 6H_2O$

Urea: $2NO + (NH_2)_2CO + \frac{1}{2}O_2 \longrightarrow 2N_2 + H_2O + CO_2$

The reaction mechanism itself involves NH_2 radicals that attach to NO and then decompose. The reaction needs a certain minimum temperature to happen, otherwise the NO and the ammonia don't react. As flue gas temperatures are reduced, the unreacted, excess ammonia can react with other combustion species, primarily with sulfur trioxide (SO_3) to form ammonia salts. The major ammonium products formed are ammonia sulfate [$(NH_4)_2SO_4$] and ammonia bisulfate ($NH_4H_2SO_4$). Ammonia sulfate is a dry fine particulate (1 to 3 microns in diameter) that may contribute to plume formation. The ammonium bisulfate is a highly acidic and sticky compound, which when deposited on downstream equipment such as air heaters, contribute to significant fouling and plugging.

Other limiting factors in the design of the SNCR system beside the ammonia slip fouling factor is urea consumption and the Unit heat rate impact.

2.0 AEP SNCR System General Design Basis

The AEP SNCR system design basis is defined in AEP technical specifications which establish process equipment standards, system design criteria, as well as the safety and performance expectations for the material storage, handling, processing, injection control, and the system's ability to reduce the NOx emission rate with minimal ammonia slip. The design specification of the system requires modularization of the process equipment in order to minimize the installation footprint, centralize the system control, and simplify the equipment installation. The SNCR injection system consists of two equipment module skids: the Urea Solution Feed Day Storage & Supply Circulation Module which is designed to receive, store, and circulate urea solution for on-demand use; and the Process Feed Dilution & Injection Control Module which is designed to meter and dilute the process urea solution for controlled furnace injection.

The AEP SNCR system design basis requires the use of aqueous urea solution in the range of 40 to 50% urea by weight to be stored on site in quantities determined by specific unit demands and location constraints. The SNCR system urea solution supply is designed to receive either commercial aqueous urea solution which is 50% urea by weight or receive and store 40% aqueous urea solution from other AEP SCR units that produce urea solution. Depending on the unit location, the as received urea solution is either stored on site in a bulk storage tank designed at a capacity large enough to meet several days storage, and/or can be received from another AEP plant's SCR system urea storage reserve and then loaded directly into the SNCR system's unit specific storage tank.

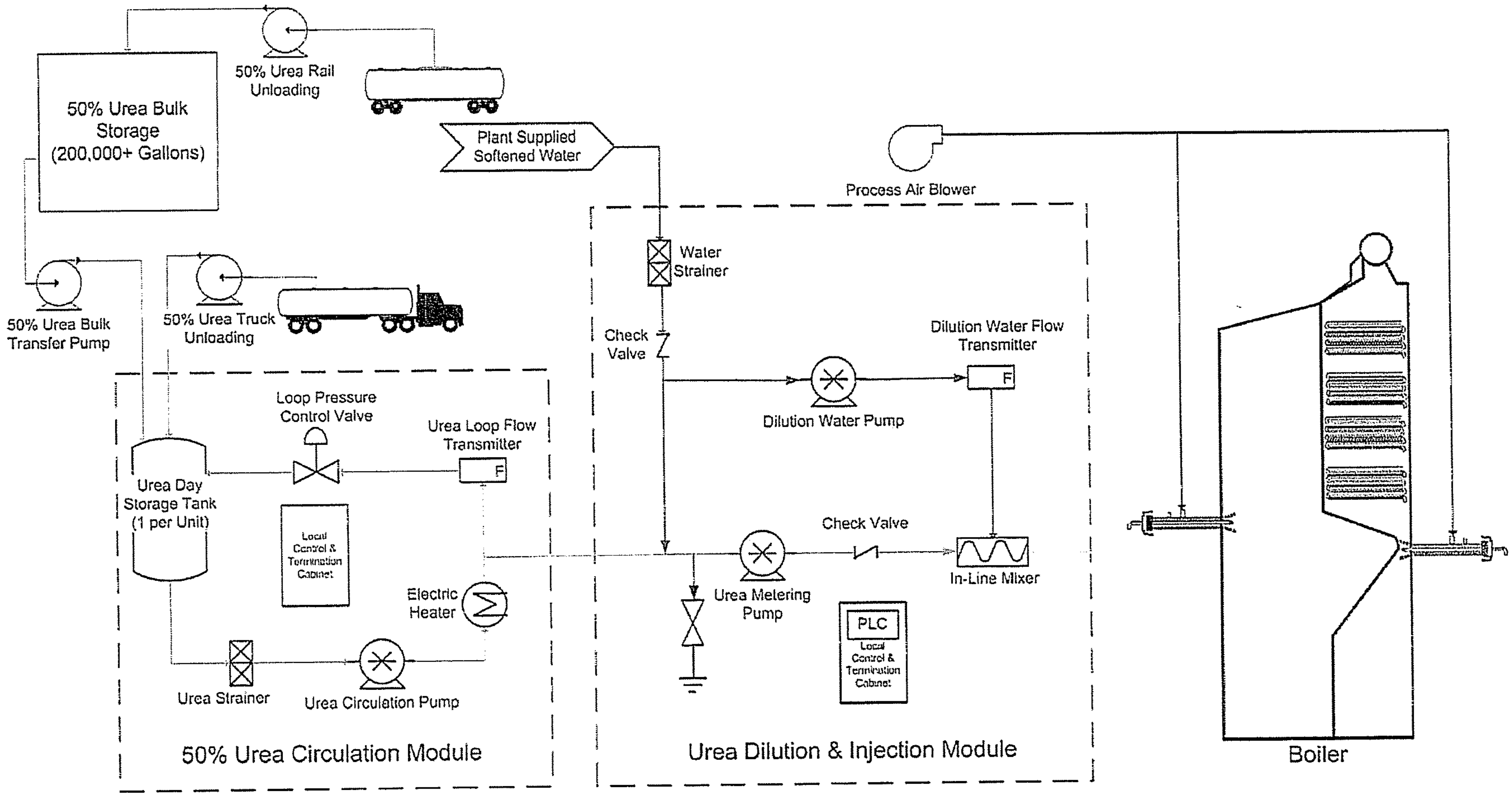
AEP Selective Non-Catalytic Reduction System Process Description

The SNCR system is designed to keep the 40 to 50% urea in solution, in sufficient quantity, and under sufficient pressure, temperature, and concentration for on-demand controlled boiler furnace injection which considers changing unit load and variations in the NOx emissions rate. This on-demand urea supply loop consists of urea day storage tanks, a urea circulation pump, heater, and pressure control valve. The solution inside the day storage tank is maintained within a certain level range through the controlled transfer from an on-site bulk urea storage tank or from direct filling from a urea transport tanker truck. From the day storage tank, the urea solution is maintained at constant pressure and temperature with continual circulation up to the urea injector zones and back to the day storage tank. This urea circulation loop is known as the Urea Solution Feed Day Storage & Supply Circulation Module. **Refer to Figure 1 – AEP SNCR System Process Flow Schematic.**

AEP Selective Non-Catalytic Reduction System Process Description

Figure 1. AEP SNCR Process Flow Schematic

(standard arrangement)



AEP Selective Non-Catalytic Reduction System Process Description

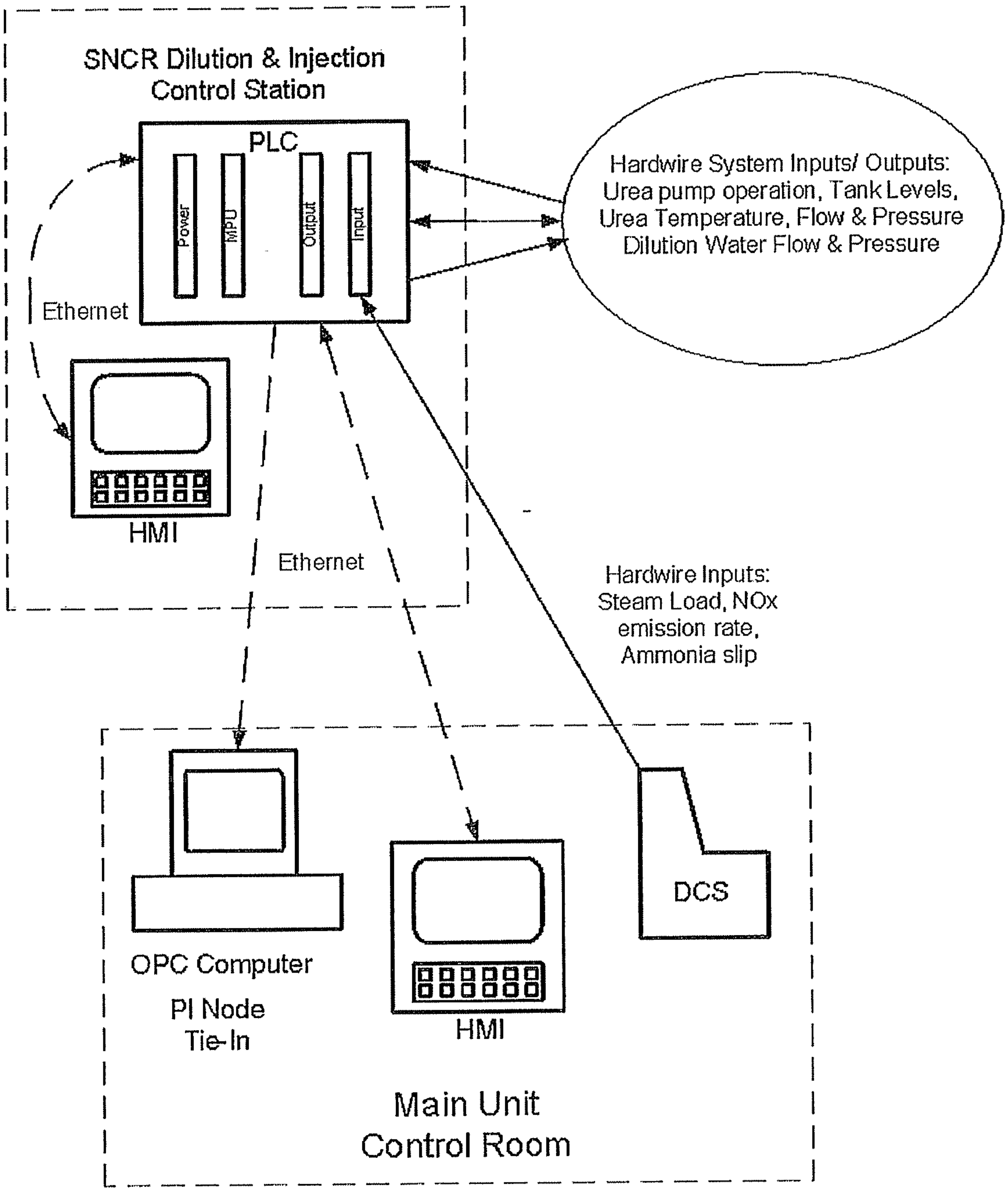
The system urea injection is controlled under a Process Feed Dilution & Injection Control Module. The 40 to 50% urea solution is further diluted for boiler furnace injection through the mixing of plant supplied water at a defined quality. Through remote process inputs to the system's programmable logic controller (PLC), the draw rate of urea solution from the feed day storage & supply circulation module as well as the urea dilution water rate is determined.

The urea dilution and injection module not only controls the amount of urea used for injection but also is designed to control the furnace injection location by designating furnace injection zones. Urea injection zones may be characterized by general locations such as the boiler front wall, rear wall, or through multiple furnace elevations, depending on the unit size, configuration, and the system supply vendor's design. Each injection zone will contain multiple injection port assemblies. The number of injectors in a zone are again dependant on the unit size, configuration, and the system supply vendor's design. Each injector consists of a removable injection lance or probe. Depending on the system's supply vendor's design, the injection lance may contain provisions for process carrier air for cooling and urea spray distribution as well as aspirating air for probe removal.

The injection and dilution water control rates are determined through *feed-forward* PLC control logic programming which is established during system start-up and is primarily based on unit steam flow. Feedback on the measured NOx emissions rate is configured into the PLC programming for NOx control trim optimization with the ability for operator bias. Runback control of the urea feed rate is based on the degree of ammonia slip measured. **Refer to Figure 2 - AEP SNCR System Control Equipment Configuration.**

AEP Selective Non-Catalytic Reduction System Process Description

Figure 2. AEP SNCR System Control Equipment Configuration (typical)



AEP Selective Non-Catalytic Reduction System Process Description

3.0 Sulfur Trioxide Flue (SO_3) Gas Conditioning (FGC) Process Overview

Low sulfur coals generally present fly ash collection issues at the unit electrostatic precipitator due to fly ash being high in resistivity (> 5×10^{10} ohm-centimeters). To lower the fly ash resistivity for improved precipitator performance, the addition of a sulfur trioxide (SO_3) flue gas conditioning (FGC) system has become a relatively low cost environmental control retrofit technology option for fossil fuel power plants that have either undersized precipitators or have switched to lower sulfur coal for fuel. The SO_3 chemical is injected in the boiler's flue gas duct down stream of the unit air heater and upstream of the precipitator where it combines with moisture in the flue gas to form sulfuric acid (H_2SO_4) which then coats the fly ash particle surface. This conditioning process lowers the fly ash particle resistivity and allows it be become collected in the precipitator through static charging.

Because the SNCR process consumes the SO_3 generated from the fuel combustion, the fly ash resistivity characteristics are likely to change. Having the ability to operate a SO_3 FGC system with sufficient injection control serves as an important safeguard for particulate emissions collection on units with known precipitator performance challenges prior to the installation of the SNCR. In addition to having an effect on fly ash collection from operating the SNCR, the ammonium sulfate generated from running the SNCR has shown to result in stack plume formation and proper fly ash conditioning control can mitigate the plume effects thorough improved precipitator performance. **Note: The SO_3 FGC system requirement with SNCR technology is to be evaluated on a unit by unit basis with consideration of coal management, precipitator box design and size among other factors.**

4.0 AEP SO_3 FGC System General Design Basis

The AEP SO_3 FGC system design basis is defined in AEP technical specifications which establish process equipment standards, system design criteria, as well as safety and performance expectations for the material storage, handling, processing, injection control, and the system's effect on stack opacity and electrostatic precipitator (ESP) operation. The design specification of the system requires modularization of the process equipment in order to minimize the installation footprint, centralize the system control, and simplify the equipment installation. The SO_3 FGC system consists of two equipment module skids: the Feed Stock Supply & Metering Module which is designed to receive, store, and transfer sulfur feed stock to the system's sulfur burner; and the Gasification & Injection Module which is designed to combust and convert the sulfur feed into SO_3 gas for controlled flue gas treatment.

Elemental sulfur is delivered to the plant as either dry granular pellets or as a molten liquid. In dry systems, the sulfur is stored for use in either a hopper or silo and is metered into the system's burner using equipment such as a variable speed feeder and conveying air. In the molten feed system design, the sulfur is kept in a heated storage vessel and metered to the system's burner using a variable speed drive tank submersible pump. This storage handling and sulfur feed process is defined as the Feed Stock Supply & Metering Module. The variable sulfur feed rate control corresponds to the SO_3 conditioning rate.

Dry or molten sulfur is fed directly into the SO_3 FGC system's sulfur burner where it mixes with hot combustion air. The combustion of the sulfur generates SO_2 gas at 600 to 700 °F. The SO_2 gas next passes through a catalyst material inside a converter vessel where an exothermic chemical reaction occurs to generate the desired SO_3 gas at a temperature between 800 and 1000 °F. The SO_3 gas leaves the converter vessel and is directly injected into the flue duct through a series of probes designed to evenly distribute the treatment gas in the duct. This combustion and conversion process is defined as the Gasification & Injection Module. The primary equipment items in this module include: the sulfur burner, combustion air heater, air blower, converter, and purge air system which are contained inside a weather proof enclosure. In certain vendor designs, the converter vessel may reside outside of the enclosure, remote to the equipment module and positioned near the duct injection ports in order to reduce the length of SO_3 gas piping.

AEP Selective Non-Catalytic Reduction System Process Description

5.0 Urea Chemical Reference Information

Urea is an organic compound with the chemical formula $(NH_2)_2CO$.

Urea is also known by the International Nonproprietary Name (rINN) carbamide, as established by the World Health Organization. For example, the medicinal compound hydroxyurea (old British Approved Name) is now hydroxycarbamide. Other names include carbamide resin, isourea, carbonyl diamide, and carbonyldiamine

Urea Commercial production

Urea is commercially produced from two raw materials, ammonia, and carbon dioxide. Large quantities of carbon dioxide are produced during the manufacture of ammonia from coal or from hydrocarbons such as natural gas and petroleum-derived raw materials. This allows direct synthesis of urea from these raw materials.

The production of urea from ammonia and carbon dioxide takes place in an equilibrium reaction, with incomplete conversion of the reactants. The various urea processes are characterized by the conditions under which urea formation takes place and the way in which unconverted reactants are further processed.

Unconverted reactants can be used for the manufacture of other products, for example ammonium nitrate or sulfate, or they can be recycled for complete conversion to urea in a total-recycle process.

Two principal reactions take place in the formation of urea from ammonia and carbon dioxide. The first reaction is exothermic:

$2\ NH_3 + CO_2 \rightarrow H_2N\text{-}COONH_4$ (ammonium carbamate)

Whereas the second reaction is endothermic:

$H_2N\text{-}COONH_4 \rightarrow (NH_2)_2CO + H_2O$
Both reactions combined are exothermic.

The process, developed in 1922, is also called the Bosch-Meiser urea process after its discoverers.

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 19, lines 9-12

a. For all environmental and non-environmental capital expenditures in the AEP system exceeding $50 million in the last seven years, please provide the initial engineering and design cost estimate, the Company's "Phase IIb" estimate, the final selected bid price, the cost presented for recovery to Commissions in CPCN, predeterminations or rate cases, and the actual incurred cost to AEP.

RESPONSE

Please see Attachment 1 to this response.

WITNESS Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 18, lines 14-17.

a. Please provide the engineering and design analyses, summaries and workpapers used to develop the cost estimates for the dry FGD at Big Sandy 2. If multiple estimates were procured by the Company, please provide all estimates.

b. Please provide the engineering and design analyses, summaries and workpapers used to develop comparative cost estimates for a wet FGD at Big Sandy 2. If multiple estimates were procured by the Company, please provide all estimates.

c. Please provide the engineering and design analyses, summaries and workpapers used to develop comparative cost estimates for landfill development work at Big Sandy 2. If multiple estimates were procured by the Company, please provide all estimates.

d. Please provide the engineering and design analyses, summaries and workpapers used to develop comparative cost estimates for boiler upgrades at Big Sandy 2. If multiple estimates were procured by the Company, please provide all estimates.

RESPONSE

a-b. Please see the enclosed CD.

c. Please see the response to Sierra Club 1-5.

d. There were no unit-specific comparative cost estimates for boiler upgrades at Big Sandy 2 developed by or procured for KPCo. The current boiler upgrade estimates are based upon the actual costs of essentially identical work performed on four other 800 MW units on the AEP fleet, namely Amos Units 1&2 and Mitchell Units 1&2.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 18, lines 20-22

a. Please provide the engineering and design estimate and final cost accounting, broken down by component, for the "most recent WFGD installation project" and the "two other recent WFGD projects" referenced here.

b. AEP has had some problems with recent scrubber installations at Cardinal, Conesville, Mountaineer, and Mitchell. Are those problems being addressed, and is any cost of avoiding those problems here factored in?

RESPONSE

a. Please see page 2 of this response (Direct Cost Only). Please see response to Sierra Club 1-31 for total dollars including overheads and AFUDC.

b. The referenced FGD installations utilize wet FGD technology, while Big Sandy Unit 2 will utilize dry FGD technology. The problems encountered are generic to those wet systems and not dry systems.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Direct Testimony of Robert L. Walton, page 18 line 20 through page 19 line 2.

a. Please list the modifications to "reflect a DFGD installation on Big Sandy 2." Provide reference case costs and dollar value changes for each specific component changed or modified, removed, or added.

b. Please list all DFGD installations used to compare the cost of installation.

c. Please identify other plants in the US that have fully installed and operational DFGD and the capacity of those plants.

d. Please identify other plants in the US that are installing or have proposed installing DFGD and the capacity of those plants.

RESPONSE

a. Please see response to Sierra Club Item No. 29 for actual cost of the last scrubber project (Conesville Unit 4) as referenced on Walton testimony, page 18, line 20.

The modification of the $/kw of the last WFGD installation to reflect a DFGD installation used a 0.80 factor. This cost was then escalated by annual rate of 5.1% to reflect the time of performance of the Big Sandy 2 project and potential market conditions and a 20% contingency was then applied.

b. The cost of installation was not compared to other DFGD installations.

c-d. AEP does not have the information requested for utilities it does not own or operate.

WITNESS: Robert L Walton

Kentucky Power Company

REQUEST

Direct Testimony of Walton page 19, lines 9-12

a. For all environmental and non-environmental capital expenditures in the AEP system exceeding $50 million in the last seven years, please provide the initial engineering and design cost estimate, the Company's "Phase IIb" estimate, the final selected bid price, the cost presented for recovery to Commissions in CPCN, predeterminations or rate cases, and the actual incurred cost to AEP.

RESPONSE

Please see Attachment 1 to this response.

WITNESS Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 7, lines 3 to 21.

a. Please describe the initiatives KPC has underway to encourage the wise and efficient use of energy.

b. Please describe additional initiatives KPC has under consideration to encourage the wise and efficient use of energy over the 30 year period used for its economic evaluation (2011 through 2040).

c. Please describe the metric that KPC uses to measure "wise" use of energy and the rationale for choosing that metric.

d. Please describe the metric that KPC uses to measure "efficient" use of energy and the rationale for choosing that metric.

RESPONSE

a. Please refer to the Company's response to Sierra Club 1-8.

b. Please refer to the Company's response to Sierra Club 1-9. The Company has had some preliminary discussions on the use of Volt Var Controls which reduce energy and demand consumption by reducing the volts needed to maintain an acceptable level to run all of the equipment within a home or business. The Company supports gridSmart and is constantly looking at ways to encourage the wise and efficient use of energy.

c-d. Cost benefit analyses are required by Kentucky statute KRS 278.285 when filing for new or expanded demand-side management programs. Kentucky Power evaluates energy efficiency and demand response programs using the analytical methods described in the California Standard Practice Manual, calculating results of the Total Resource Cost (TRC), Ratepayer Impact Measure (RIM), Participant, and Utility Cost Tests. Favorable test results (where benefits exceed costs) are indicative of such programs and measures that will promote the wise and efficient use of energy by Kentucky Power's customers.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 7, lines 3 to 21.

a. Please describe the metric that KPC uses to measure "planning flexibility" and the rationale for choosing that metric.

b. Please describe the metric that KPC uses to measure "optimum asset mix" and the rationale for choosing that metric.

c. Please describe the metric that KPC uses to measure "adaptability to risk" and the rationale for choosing that metric.

d. Please describe the metric that KPC uses to measure "affordability" and the rationale for choosing that metric.

RESPONSE

a-d. The plan characteristics listed in this request are considered "other objectives" of a resource plan as defined by Kentucky statute. The primary objective, as defined by the statute, is to "assure the reliable, adequate and economical supply of electric power to the customer, in an environmentally compatible manner". KPCo does not use a quantitative metric to measure these "other objectives" of its resource plan. Rather, it would compare its chosen plan to other potential plans with respect to these objectives.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 7, lines 3 to 21 and pages 30 to 54.

a. Please provide the Company's assessment of the "planning flexibility" of each of the four alternative options it evaluated.

b. Please provide the Company's assessment of the "optimum asset mix" of each of the four alternative options it evaluated.

c. Please provide the Company's assessment of the "adaptability to risk" of each of the four alternative options it evaluated.

d. Please provide the Company's assessment of the "affordability" of each of the four alternative options it evaluated.

RESPONSE

a-d. KPCo did not perform this assessment for the alternatives considered. Based on the analysis the Company did prepare, Exhibits SCW-4A through 4E provide a measure of "optimum asset mix" and "affordability", and Exhibit SCW-5, Figure 5-1 provides a measure of "adaptability to risk" and, to a lessor extent, "planning flexibility".

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, page 9 at 27-30.

a. Please describe the elements of the "CCR-related costs" totaling $48 million.

b. Are these total capital expenditures, O&M expenses, or a combination of both?

c. To what extent are these costs avoidable by the retirement of the Big Sandy 2 unit?

d. Please describe and detail the full expected costs of complying with the expected CCR rule (Subtitle D) at the Big Sandy 2 unit.

e. How would these costs change if the EPA were to regulate CCR under a Subtitle C designation?

f. Please explicitly break down forward-going incremental costs and remediation costs that are unavoidable even if Big Sandy 2 is retired.

RESPONSE

a. Please see the response to KPSC 1-47.

b. The $48 million cost represents capital expenditures.

c. The costs would not be required if the unit were retired.

d. At this time, the projects comprising the estimated $48 million figure represent the set of capital cost anticipated assuming Subtitle D is implemented.

e. That estimate has not been determined.

f. Such remediation cost breakdowns have not been established.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 11 and 12, Table 1

a. Please list the hours of peak demand in which Big Sandy Unit 1 has been dispatched in the most recent five calendar years for which statistics are available, the MW dispatched and the MWH generated in each of those hours.

b. Please list the hours of peak demand in which Big Sandy Unit 2 has been dispatched in the most recent five calendar years for which statistics are available, the MW dispatched and the MWH generated in each of those hours.

c. Please provide all analyses underlying the Company's decisions in option 2 and option 3 to assume a natural gas combined cycle (CC) plant with duct-firing for peaking purposes, rather than a CC to serve base and intermediate load and a combustion turbine unit to serve peak load.

d. Please provide the heat rate(s) the Company assumed for the natural gas CC plants with duct-firing in option 2 and option 3 respectively, and the rationale supporting those assumptions.

e. Please list each natural gas CC unit that AEP currently owns or operates, and indicate which of those units has duct-firing.

RESPONSE

a. & b. This question has been interpreted as being the Big Sandy unit hourly generation that is coincident with the highest AEP-East peak demand.

	Big Sandy 1 MWh Dispatch Basepoint	Big Sandy 1 MWh Generation	Big Sandy 2 MWh Dispatch Basepoint	Big Sandy 2 MWh Generation
8/8/2007 15:00	260	260	745	789
6/9/2008 15:00	203	215	0	0
8/10/2009 15:00	269	239	714	729
7/23/2010 15:00	263	274	721	800
7/21/2011 17:00	278	277	782	794

Therefore these peak hours offer the attendant coincident generation for Big Sandy Units 1 and 2 during such AEP East System summer peaks, for the most recent 5 calendar years.

c. No analyses were undertaken to compare duct firing for peaking purposes, rather than a CC to serve base and intermediate load and a combustion turbine unit to serve peak load. However, the duct firing capability of the CC provides a lower cost option for peaking capacity than the installation of a separate CT to serve that peaking need and a CC to serve the intermediate load requirement.

d. The modeled heat rate assumptions, by unit:

[redacted]

[redacted]

The heat rates provided were based on analyses completed by Sargent & Lundy (S&L). The stated heat rates represent the cycle performance for the ambient conditions per S&L Report and ASHRAE data as the 1% Summer Wet Bulb condition.

e. AEP currently owns and operates the following three CC plants in its Eastern service territory which all have duct-firing:

1. Dresden
2. Lawrenceburg
3. Waterford

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, page 16. Please provide the STRATEGIST input and output files, in machine readable format, for each alternative option the Company evaluated.

RESPONSE

The Company is unable to provide the requested input and output files. Strategist is a proprietary utility planning application that is licensed solely by Ventyx Inc., which owns Strategist in its entirety. Kentucky Power contacted Ventyx Inc. and it confirmed that the application software, source code, database, and associated documentation, including input files, are its confidential and proprietary intellectual property. Access to the documentation may be granted solely by Ventyx Inc., at its own discretion, under a mutually binding Non-Disclosure Agreement. Access to the database and/or the application itself is granted only under exclusive license with Ventyx Inc. Ventyx does not allow access to the Strategist source code under any circumstances. Kentucky Power will assist the Sierra Club in contacting Ventyx, Inc. to obtain the required Non-Disclosure Agreement.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 16 and Exhibit SCW-1, pages 6 and 7.

a. Please explain how the Company modeled energy efficiency in Strategist. If the Company did not model energy efficiency, please explain why not?

b. Please explain how the Company modeled active demand response in Strategist. Please explain how the Company modeled passive demand response in Strategist

RESPONSE

a. The impacts of energy efficiency programs were included in the load forecast assumptions used in Strategist.

b. The impacts of active demand response were modeled through a peak shave purchase transaction in Strategist.

c. Other than the "passive" implications of energy efficiency and its attendant impact on demand that were included in the load and peak demand forecast, there were no additional passive (e.g. price response) demand response programs included in the modeling.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Did the Company include an end effects period in the STRATEGIST modeling? If so, please describe that period and the basis for it?

RESPONSE

There was no end-effects period modeled in Strategist. However, the study was conducted over the time period of 2011 to 2040. This period is sufficiently long enough to cover the life of the retrofits and the majority of the life of the gas replacement alternatives. In addition, due to the significant present worth discounting of costs after 2040, any relative cost impacts after that point would be very small.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, page 17, lines 11-23, re proxy for long-term "g(eneration)" revenue requirement. Please confirm that STRATEGIST calculates this amount as opposed to the Company calculating it based upon model outputs. If the Company cannot confirm please explain why not.

RESPONSE

Yes, the extracted values for the study period reflected in Exhibit SCW-4, as well as the supporting Exhibits SCW-4A through 4E, came directly from Strategist output.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, page 18, lines 9-10, re the STRATEGIST model "locking-in" the timing and selection of various resources.

a. Did the Company perform any model runs in which it made these resource options available to STRATEGIST and allowed the model to select the optimal resource portfolio?

b. If yes, please describe the outcomes of these model runs and provide the relevant input and output files in machine readable format

c. If not, please explain why not.

RESPONSE

a. No, not as it pertains to the initial (2016) "disposition" option. However, Strategist through its optimization algorithm, did create the optimal (i.e., least cost) capacity expansion plan after 2016 for each of those "locked in" Big Sandy disposition alternative. During the optimization process, Strategist creates all of the possible combinations of resource alternatives available for selection. Therefore each alternative option's respective capacity expansion plan identified in the 'detailed' Exhibits SCW-4A through 4E identify the model-optimized capacity expansion plan, again, after the initial Big Sandy unit disposition alternative in 2016.

b. N/A

c. See response to a. above.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Table 1-1 of Exhibit SCW-1, page 4.

a. Please provide the Company's projection of peak demand and internal load from 2031 through 2040, and the basis for that projection.

b. Please describe the factors driving the Company's projection that the KPC compound rate of growth from 2021 to 2030 will be higher than from 2011 to 2020.

c. Please provide KPC's weather-normalized peak demand and internal load by year for 2001 through 2010, and the corresponding compound annual rate of growth for each.

d. Please provide KPC's actual, weather-normalized internal load by major retail rate class for 2001 through 2010,

e. Please provide KPC's projection of internal load by major retail rate class by year through 2030.

f. Does the AEP Economic Forecasting projection algorithm have a price elasticity component by major retail rate class? If not, why not.

g. Does the forecast in Table 1-1 reflect the price elasticity impact by rate class of the increase in rates that will result from alternative option 1? If so, please explain the feedback process used in the analysis to accomplish that.

h. Please provide a forecast of aggregate peak demand and annual energy that reflects the price elasticity impacts by rate class of the environmental surcharge by year under the Company's proposed 15 year depreciation. Please provide all supporting assumptions and workbooks, in electronic format with operational calculations.

RESPONSE

a. See attached file tab labeled 42(a).

b. Slightly slower growth in the first ten years of the Company's load forecast as compared with the second ten years can be attributed largely to efficiency gains caused by national appliance and lighting standards. These impacts are expected to impact most in the residential and commercial classes. This pattern is consistent with projections developed by the Energy Information Administration. Also see attached file tab labeled 42(b).

c. See attached file tab labeled 42(c).

d. See attached file tab labeled 42(d).

e. See attached file tab labeled 42(e)

f. Yes.

g. The load forecast input price assumptions are based on price trends and not tied to specific projects.

h. See response to 42(g).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-1, pages 4 to 7.

a. Did KPC test the sensitivity of its options to the possibility of the Kentucky General assembly passing clean energy legislation, such as the Clean Energy Opportunity Act (HB 67), which would require utilities such as KPC to achieve specified reductions from energy efficiency and to acquire specific quantities of generation from new renewable resources?

b. If yes, please explain how the Company evaluated this possibility.

c. If no, please explain why not.

RESPONSE

a. No such sensitivity tests were performed

b. N/A

c. The legislation is not finalized. Therefore, KPCo has no obligation to commit to such programs and would likely not do so, until cost recovery assurances were received from the Commission. In fact, KPCo had previously sought to acquire 100 MW of renewable (wind) resources that would presumably achieve such "clean energy" attributes; however such costs associated with that potential wind renewable energy purchase agreement were denied recovery by the KPSC.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2. Emission allowance prices under CSAPR.

a. Please provide the projection of allowance prices for emissions of SOx and NOx respectively the Company used as inputs to Strategist.

b. Please provide all analyses and research reviewed and/or prepared by the Company underlying its projection of allowance prices for emissions of SOx and NOx respectively.

RESPONSE

a. Below are Strategist's input for SOx and NOx.
$/ton –Nominal $'s

	SOx Prices	NOx Annual	NOx Summer
2012	1300	650	1400
2013	900	550	1100
2014	1800	450	800
2015	550	450	800
2016	100	450	800
2017	10	250	650
2018	0	125	250
2019	0	200	75
2020	0	0	0

b. The Cross State Air Pollution Rule (CSAPR) allowance prices were developed to reflect the design of the environmental regulation.

During the first stage of price formation, the company developed a series of non-market, state specific "shadow" prices using Aurora^{XMP} to achieve compliance with the regulation.

During the last stage of price formation, the company incorporated market-based dynamics into the prices to reflect the intra-group trading provision of the regulation.

The final allowance prices were then benchmarked against the Environmental Protection Agency (EPA) and other third-party consultants allowance prices.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2. CO2 prices.

a. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for CO2 prices from 2022 through 2040.

b. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "FT-CSAPR: Higher Band" assumption for CO2 prices from 2022 through 2040.

RESPONSE

a. & b. The "base (FT-CSAPR)" carbon dioxide price (CO2) and the "FT-CSAPR: Higher Band" CO2 price reflect a national carbon tax and an industry consensus view. The price is escalated by the forecasted Consumer Price Index. The final price is benchmarked to proprietary third-party estimates.

A consensus view represents the amalgamation of various sources of information. The long-term forecast is shaped by the views of many stakeholders, including, but not limited to:

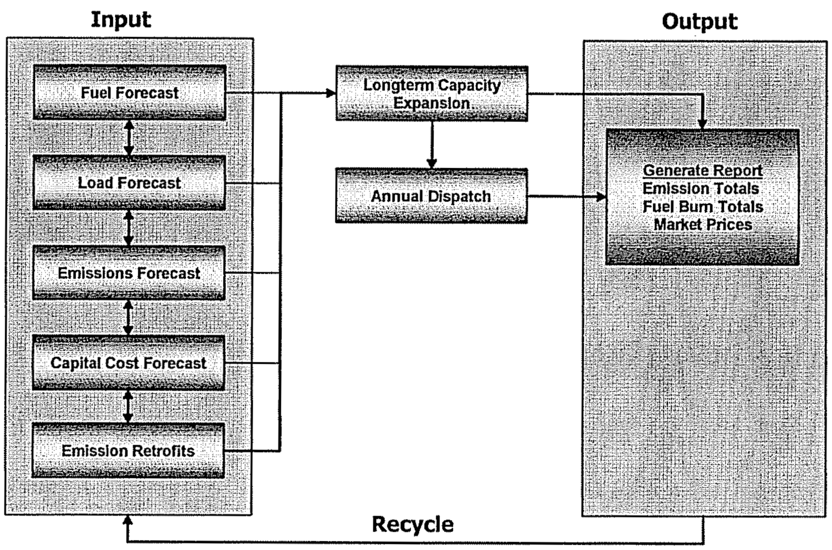
Investment Community - Equity and Fixed Income analysts
Third-Party Consultants - IHS Cera, PIRA, Wood Mackenzie
Industry Groups - Edison Electric Institute
Government Agencies - EPA, DOE, NERC, FERC
Trade Press - Argus Air Daily, Coal Daily, Coal Weekly, The Energy Daily, Megawatt Daily, Gas Daily
Various Stakeholders - Independent System Operators, Interest Groups (Environmental and Industry)
Energy Companies - Listen to earnings calls, press releases, SEC filings, etc
Internal Information - Experience from other organizations within the company.
Independent Studies - Proprietary research studies

The company uses this information to develop and test the robustness of the long-term forecast. In the case of opposing views, we use the contrary position to better understand the reasons that support our view. At times, we have differing views from other stakeholders.

The long-term forecast represents a fundamental view of the primary drivers to the energy market. Each primary driver (supply, demand, fuel, policy, etc) is developed by company experts and reflects public and non-public information. These industry views represent a sustainable outlook over the forecast period.

A third-party dispatch model, AuroraXMP, uses the industry views to create a series of long-term industry projections: electricity price, fuel consumption, new build, retirements, etc. Figure 1: illustrates the forecast process.

Figure 1: AuroraXMP Forecast Process



After each forecast, company experts review the results for robustness and iterate until the market reaches equilibrium. The final outlook is benchmarked to the consensus view.

WITNESS: Scott C Weaver, Karl R. Bletzacker

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2. Coal prices.

a. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for NAPP and CAPP coal prices respectively.

b. Please provide the estimate of transport costs and other incurred costs between mine mouth prices for NAPP and CAPP coal, and Big Sandy 2. Provide analysis and research reviewed and/or prepared by the Company supporting such estimates.

RESPONSE

Please see the response to KPSC Staff 1-78.

WITNESS: Scott C Weaver, Karl R Bletzacker

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2.PJM on-peak and off-peak energy prices.

a. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for on-peak energy (PJM-AEP Gen hub) from 2015 through 2040.

b. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "FT-CSAPR: Upper Band" and "FT-CSAPR: Lower Band" assumptions for on-peak energy (PJM-AEP Gen hub) from 2015 through 2040.

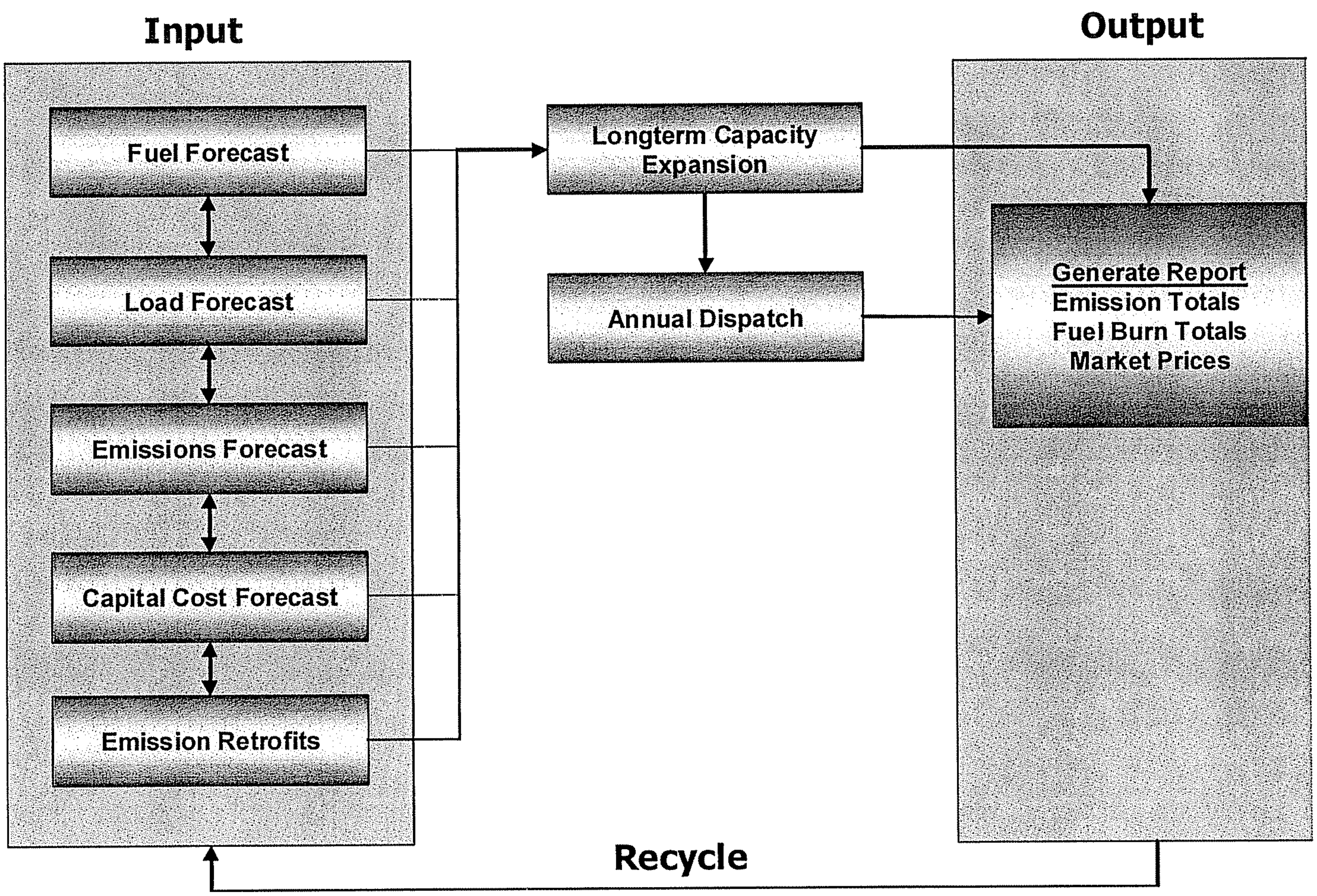
c. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for off-peak energy (PJM-AEP Gen hub) from 2015 through 2040.

d. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "FT-CSAPR: Upper Band" and "FT-CSAPR: Lower Band" assumptions for off-peak energy (PJM-AEP Gen hub) from 2015 through 2040.

RESPONSE

The "base," "FT_CSAPR: Upper Band," "FT-CSAPR: Lower Band," forecasts are developed using the AuroraXMP dispatch model. The model relies on key input variables, including, but not limited to, supply, demand, fuel, and environmental regulations. Figure 1 illustrates the general forecast process.

Figure 1: AuroraXMP Forecast Process



The "base" forecast represents a sustainable view of key inputs. Upper and Lower Band forecasts measure the sensitivity of the "base" forecast to sustainable changes in fuel prices (coal and natural gas), emission prices (excluding carbon dioxide), and electricity demand.

The "base" forecast incorporates the following views:

Supply: - The long-term forecast incorporates a shift from coal to natural gas plants as a result of low natural gas prices and restrictive environmental regulations. Coal plants are expected to account for the largest share of total retirements.

Fuel: - There are four major driving forces that shape the long-term outlook for natural gas.

· Abundant, relatively low-cost natural gas supplies: Natural gas reserves and productive capacity will continue to grow domestically and globally as shale gas extraction technology becomes widespread. Despite current negative reaction, the environmental impacts of shale gas development will ultimately be manageable.

· Natural gas is a cost-effective fuel for electric generation: In a carbon-constrained environment, gas-fired generation remains the low-cost means to reduce emissions. Natural gas-fired capacity will play the key role in providing back-up to intermittent renewable energy.

· Natural gas pipeline capacity will keep pace with the evolving locations of supply and consumption: The extensive domestic natural gas transportation infrastructure is sufficiently robust to overcome constraints through existing capacity expansions, flow reversals, and new construction.

· The role of natural gas spans many sectors of the economy: Demand for natural gas in the expanding global economy will increase as electric generation, residential/commercial space heating and industrial processes are all advantaged with lower natural gas prices. However, a revolutionary transition to compressed natural gas usage in the transportation sector is unlikely.

There are four major driving forces that shape the long-term outlook for coal.

· Strict regulations on environment and safety: The U.S. EPA began implementation of strict water quality standards for coal mining, especially for mountaintop removal mining practices. Currently, approximately half of the coal production in Central Appalachia (CAPP) comes from surface mines and may be affected by EPA regulations. Since the April 2010 Upper Big Branch mine disaster, the Mine Safety and Health Administration (MSHA) has further tightened mining safety regulations for underground mining. MSHA inspectors visit mines more frequently, which may expose safety issues earlier but may also adversely affect mine production and lower mine productivity.

· Competition from inexpensive natural gas: The development of shale gas extraction technology unlocks inexpensive and abundant natural gas. In 2010, the average natural gas price at the Henry Hub remained relatively low at $4.37/mmBtu, which put natural gas in direct competition with coal for power generation. Coal-to-natural gas switching for power generation dampens the electric power sector coal demand, especially in the U.S. southeast, where delivered coal prices were already high due to elevated transportation costs.

. Massive retirement of coal-fired plants: Domestic coal demand is projected to decline after massive coal-fired plant retirement due to implementation of HAPs. Currently, the U.S. power sector consumes more than 90% of coal, and massive coal plant retirement dampens coal demand significantly. Lower demand puts downward pressure on coal prices. Environmental controls installed to comply with HAPs will increase coal plant fuel flexibility, and reduce pressure on CAPP coal supply.

- High U.S. coal exports: The U.S. economic recovery was slower than expected in 2010, as was the demand for electricity and energy commodities. However, emerging economies in Asia were strong because they were hit less severely by the global economic downturn, and recovered faster. Demand for coal in global markets, especially in the Asian market for both metallurgical and thermal coal, grew stronger in 2010. Flooding in Australia's coal mining region from November 2010 through January 2011 disrupted Australian coal exports. Again, as in 2008, the U.S. coal producers seized the opportunity of high international coal demand, and exported historically high volume of 81.7 million tons coal in 2010, 22.6 million tons more than 2009 and 0.2 million tons more than 2008.

Demand: The Economic Forecasting Group has developed load forecasts for three major regions of the U.S. electric industry, i.e., Eastern, ERCOT and Western interconnects, with these regions having 12, 4 and 12 zones, respectively. The aggregate projected growth rate for the forecast period is 1.0%. Within the regions served by AEP, in aggregate they lag the U.S. in economic and load growth. The slowest growing regions within AEP are the AEP-East Zone, with growth being adversely affected by competitive pressures facing the automotive, coal mining and steel industries and the AEP-SPP Zone.

Environment: The environmental portion of the forecast is the most dynamic portion of the long-term forecast. Each year, AEP considers the best available information to develop its view of environmental markets. The following section describes the environmental view incorporated into the long-term forecast and recognizes that future environmental policy may be different from those views assumed in this forecast.

Cross-State Air Pollution Rule (CSAPR): In response to the D.C. Circuit Court's vacatur of the Clean Air Interstate Rule (CAIR), the Environmental Protection Agency (EPA) released CSAPR as a replacement rule. Specifically, CSAPR addresses the Court's concern of air pollution across state boundaries by transitioning from a regional cap-and-trade program to state specific emission limits. The covered states will be required to limit the sulfur dioxide and nitrogen oxides emission to an amount, in most states, below current levels. Allowances can be traded within individual groups, however, total allowances cannot exceed allocated allowances. In 2014, state emissions cannot exceed state assurance levels without incurring a penalty payment. On December 30, 2011 the court issued a stay of the rule. The final outcome is yet to be determined.

Mercury Air Toxic Standard (MATS): On February 8, 2008, the D.C. Court vacated the Clean Air Mercury Rule (CAMR) governing the release of mercury emissions. As expected, the replacement rule establishes a Maximum Achievable Control Technology (MACT) standard for

Hazardous Air Pollutions (mercury, acid gases, and other organic air toxins) rather than a market-based program. The revised command-and-control program will require coal and oil plants to meet specific emission limits or be forced to retire.

Coal Combustion Residuals (CCR or Coal Ash): In response to the massive coal ash spill at the Tennessee Valley Authority's Kingston facility, EPA began the process of regulating the waste (residuals) from the combustion of fossil-fuels. The proposed rule includes hazardous and non-hazardous options that could require wet ponds to either install liners or convert to dry storage.

Cooling Water Intake Structures – 316(b): Section 316(b) of the Clean Water Act governs the withdrawal of cooling water to protect aquatic organisms. In particular, the proposed rule establishes requirements to limit aquatic impingement (being pinned against screens) and entrainment (being drawn into cooling water systems) by power plants. According to the proposed rule, the EPA is not pursuing the most restrictive policy (closed-cycle cooling systems) by allowing site-specific flexible technology options.

Carbon Dioxide (CO2): In the absence of federal legislation, carbon emissions are currently being addressed through regulation. Specifically, the EPA has been implementing the greenhouse gas New Source Performance Standards and Best Available Control Technology regulations of coal plants. Moreover, carbon emissions are regulated through State and Regional programs. In the future, the long-term forecast incorporates a national carbon tax with non-binding emission targets.

The Upper Band forecast measures the sensitivity of the "base" forecast to sustainable higher fuel prices (coal and natural gas), emission prices (excluding carbon dioxide), and electricity demand.

The Lower Band forecast measures the sensitivity of the "base" forecast to sustainable lower fuel prices (coal and natural gas), emission prices (excluding carbon dioxide), and electricity demand.

See also the response to Staff 1-68.

WITNESS: Scott C Weaver, Karl R. Bletzacker

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 20 and Exhibit SCW-2, page 2. PJM RPM capacity prices.

a. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "base" fleet assumption for capacity value (PJM-RTO RPM) from 2015 through 2040.

b. Please provide all analyses and research reviewed and/or prepared by the Company underlying its "FT-CSAPR: Lower Band" assumption for capacity value (PJM-RTO RPM) from 2015 through 2040.

RESPONSE

a. The "base" capacity prices are fundamentally derived from the Aurora XMP dispatch model. The price reflects the non-energy revenue requirement to ensure system reliability.

b. The "FT-CSAPR: Lower Band" capacity prices are fundamentally derived from the Aurora XMP dispatch model. The price reflects the non-energy revenue requirement to ensure system reliability.

Also see the response to Sierra Club 1-47 and KPSC Staff 1-68.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 21.

a. For Option 1, please provide the assumptions used as inputs to Strategist for the major non-environmental related capital costs KPC expects to incur in order to keep Big Sandy Unit 2 running through 2040, e.g. boiler rebuilds, superheaters, reheaters, or waterwall tubes, etc.

b. If KPC did not assume any future non-environmental capital costs for Option 1 please explain why not.

c. Please provide all major non-environmental related capital costs KPC incurred by year from 2002 through 2011.

RESPONSE

a. Please see Attachment 1, page 1 of 2, for costs through 2020. Capital costs beyond 2020 were escalated using a 5-year rolling average.

b. N/A

c. See Attachement 1, page 2 of 2 for data back to 2004. The current reporting system does not have data in this format prior to 2004.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, Exhibit SCW-1.

a. Did the Company include plant retirement/decommissioning costs?

b. If yes, please provide the assumed costs and explain how the Company modeled them in Strategist.

c. If no, why not?

RESPONSE

a. No. Plant retirement/decommissioning costs were not included in the unit disposition analysis summarized on Exhibit SCW-4.

b. See the response to part a.

c. As indicated in Mr. Weaver's direct testimony beginning on page 48, line 19, through page 49, line 6, such retirement-related costs associated with pre-existing generating assets (i.e., undepreciated plant balances) were assumed to be recoverable going-forward and would, therefore, not have an incremental impact on the relative disposition economics in Strategist and set forth in Exhibit SCW-4. If , however, the Company were to seek accelerated recovery of any such retirement-related costs, then any of the "non-retrofit" options for Big Sandy 2 (Options #2 through #4) would add such costs to the respective 'CPW' costs of those options. Although decommissioning costs, net of salvage, were also not estimated, if these costs had been projected, the CPW costs of those non-retrofit options would likewise be incrementally burdened, further improving the relative economics of Option #1 (Big Sandy 2 Retrofit).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, Table 1 and pages 23 to 30

a. Please provide all analyses underlying the Company's decision to assume the four alternative options summarized in Table 1, as opposed to other possible alternative options.

b. Please explain why the Company did not choose to evaluate an alternative option in which it would retire Big Sandy units 1 and 2 and replace them with a mix of "steel in the ground" gas CC units and purchases, but starting with a lower initial quantity of new gas CC capacity coming into service January 2016, for example 350 MW, followed by a second addition on new gas CC capacity coming into service five years later?

c. Has the Company had any discussions with LG&E and KU regarding joint development of a gas CC unit to come into service in 2016 and an additional unit to come into service a few years later? If so, please document those discussions. If not, why not.

RESPONSE

a. The four alternative options were viewed by KPCo's management as a reasonable basis for the performance of the Big Sandy disposition analysis. However, as identified beginning on page 40, line 11, through page 42, line 3, of Mr. Weaver's testimony, additional long-term "market" alternatives were effectively proxied by Option #2 (Replace with a [Brownfield] CC. Likewise, Options #4A and #4B (Replace with [Short-Term] PJM-Market Capacity & Energy... for 5 and 10 years, respectively; then replace with a CC) also has many of the same attributes as replacing with a Peaking Asset (i.e. natural gas Combustion Turbine units). Based on the fact that the AEP Fundamental Analysis group's long-term forecast of PJM capacity value used for that Option assessment are projected to approach the anticipated PJM Net Cost of New Entry value (Net CONE) --for which PJM utilizes the net cost of *peaking generation* to establish-- one could also then assert that this Options #4A and #4B very reasonably approximate a "peaking asset" alternative.

See also the response to KIUC Item No. 29, First Set.

b. The Company viewed an approximate 700-800 MW CC replacement (or, a size roughly equivalent to that of Big Sandy Unit 2 it would be replacing) set forth in Option #2, as being more appropriate for analysis purposes than multiple smaller, staggered, CC units. There are certain economies of scale that are created by exercising a combined cycle plant build option that would require a "2x2x1" (2 combustion turbine x 2 heat recovery steam generators [HRSG] x 1 steam turbine) design. A combined cycle unit in approximately the 350 MW size would typically be a "1x1x1" design having a higher relative installed cost per kW of capacity; as well as a higher heat rate (i.e., poorer thermal efficiency). Internal AEP estimates suggest that this $ per kW difference could be significant at over +20%, while the "full load" heat rate difference could be as much as +4% for a smaller, roughly 350 MW, 1x1 CC.

c. The Company has not had any discussions with LG&E/KU regarding a joint venture to develop a gas CC unit. A joint venture does not solve any issues or concerns relative to the cost impact to the customer.

WITNESS: Scott C Weaver, Toby Thomas

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, Table 1 and pages 23 to 30. Has the Company considered any other alternatives aside from Options 1-4?

a. If so, please provide detailed descriptions of all other alternatives considered, the level to which they were considered (i.e. discussion only, analysis, modeling, etc…), and any analytical work, such that it exists, that examined the cost efficacy of these other alternatives.

b. If so, please provide any analytical work that supports the non-consideration of those alternatives in the final four options presented here.

c. If not, why not?

d. Has the Company considered the cost effectiveness of replacing Big Sandy with capacity-only replacement, such as combustion turbine without combined cycle capacity?

e. Has the Company considered the cost effectiveness of replacing Big Sandy with a mixture of capacity and energy resources, such as a mix of combustion turbines and combined cycle capacity?

f. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and renewable energy purchases in either the short or long-term (i.e. immediately, up to 5 years as in Option 4A, or up to 10 years as in Option 4B)?

g. Has the Company considered the cost effectiveness of replacing Big Sandy with any combination of fossil resources and energy efficiency, demand response, or other demand-side management acquisitions or programs?

h. If the answer to any of (d)-(e) is yes, and as not otherwise provided in answer to (a) or (b), please provide any workpapers showing the scenario considered, the expected costs of the scenario, and any model results from comparing the scenario against other alternatives.

RESPONSE

a. An additional evaluation was performed in January of 2012, after the filing of this case. This assessment focused on the possibility of either acquiring --or entering into a purchase power arrangement-- from affiliate Ohio Power Company for a portion of the Mitchell Unit 1 and/or Unit 2 facilities. These 770 MW and 790 MW, respective coal-fired units are located in Moundsville, West Virginia and have recently been environmentally-controlled with FGDs and SCRs. The timing of this alternative evaluation was based on the recent prospect that Ohio Power Company could become corporately separated and, with that, the generation assets of that company may no longer be regulated and, hence, may be available for sale/transfer.

One of these evaluations calls for the purchase of a 20% portion of the combined Mitchell Units 1 and 2 (or, a total of 312 MW) and is under consideration as a replacement for the proposed retirement of KPCo's Big Sandy Unit 1. This evaluation is intended to be introduced as a proposed component of the 'Section 205' filing with the FERC that AEP is intending to file in early 2012 that would seek to modify the AEP Interconnection (Pool) Agreement.

Additionally, KPCo management also requested that an additional analysis be performed under which Kentucky Power would seek to receive a greater portion from Mitchell Units 1 and 2 (ostensibly, one of the 'full' Mitchell units) that would serve to effectively be substituted for the like-sized Big Sandy 2. This evaluation also assumed that in lieu of retiring Big Sandy Unit 1, it would consider converting that unit to burn solely natural gas (i.e. it would become a "gas-steam" unit).

The attachment to this response is a summary of these indicative Strategist-based evaluations performed in January 2012.

b. As indicated in the response part a of this question, this assessment was performed after this KPCo filing, but does not change the results and recommendation of the filing.

c. N/A

d. The Company has not considered the replacement of Big Sandy 2 with a combustion turbine unit. If Big Sandy Unit 2 were to be retired, KPCo would be replacing a large "baseload" facility that has historically contributed significant amounts of generated energy. As such, if it were to replaced purely with peaking capability --in the form of natural gas combustion turbine (CT) units, or as a unit simply converted to burn natural gas (i.e., a gas-steam unit)--, the Company believes it could be exposed to unacceptable levels of market (energy) purchases and, with that, potential for price volatility for the long-term life of the CTs/gas conversion due to such facilities' would very likely have very low utilization/capacity factors.

e. No. However, this option is essentially captured by, particularly, Options #4A and #4B. See the response Sierra Club 1-51, part a, for an elaboration.

f. No. The Company believes that renewable energy purchases are not substitutable for, particularly, capacity planning purposes. For instance, the PJM RTO recognizes only 13% of the nameplate MW-capacity of wind generating sources for capacity planning purposes. Further, KPCo 2009 request to recover its costs under a proposed wind renewable energy purchase agreement (REPA) was denied by the Commission following opposition by KIUC and the Attorney General.

g. No. While as indicated on Table 1-2 of Exhibit SCW-1, KPCo is projected to achieve 41 MW of demand response (DR) resource by 2016, and at least 60 MW by 2020, such amounts would likely serve to merely adjunct KPCo's resource portfolio, rather than offer a major contribution. As with peaking resources, DR would not contribute much in the way of *energy* contribution. Likewise, that same Table 1-2 of Exhibit SCW-1 also indicates as much as nearly 100 GWh of (annual) energy efficiency contribution being projected for the Company by 2016. However, that level also represents a small (< 2%) percentage of KPCo's overall internal load estimate for that year.

h. N/A

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, page 11 and 12, page 53 and Exhibit SCW-1 pages 3 to 6.

a. Please indicate the annual capacity and annual generation the Company has obtained by source in each of the most recent 5 calendar years.

b. Please indicate the capacity and annual generation the Company projects it would obtain from Big Sandy Unit 1 in each year, 2011 through 2030, if it were not to retire the unit; if this answer differs for different scenarios, please provide the answer for each scenario.

c. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 1, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

d. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 2, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

e. Please provide the Company's projected mix of capacity and generation by source through 2030 under alternative option 3, e.g. capacity and generation from owned units, capacity and generation from the AEP fleet, purchases of firm capacity and of generation.

f. Please provide the Company's projected energy and peak load requirement, broken down by sector, through 2030.

g. At what date in the future does KPC expect to require additional capacity should Big Sandy 2 not be retired?

h. At what date in the future does KPC expect to require additional capacity should Big Sandy 2 be retired?

i. At what date in the future does KPC expect to require additional energy should Big Sandy 2 not be retired?

j. At what date in the future does KPC expect to require additional energy should Big Sandy 2 be retired?

RESPONSE

a. Below is the annual capacity and generation for KPCo's most recent 5 calendar years.

Capacity (MW)	2007	2008	2009	2010	2011
Big Sandy	1,060	1,060	1,060	1,077	1,078
Rockport 1	195	198	198	198	198
Rockport 2	195	195	195	195	195
Total	1,450	1,453	1,453	1,470	1,471
Energy (GWh)					
Coal	7,533	6,021	6,262	6,552	6,373
Other*	1,918	3,097	2,200	2,167	1,859
Total	9,451	9,118	8,462	8,720	8,232
* Net Pool Interchange					

b. Below is the capacity and generation by pricing scenario for Option #3 where Big Sandy Unit 1 does not retire but is repowered as a CC unit. This represents the <u>only</u> option evaluated that does not retire Big Sandy Unit 1 effective 2015.

Big Sandy 1						
	Nominal Capacity Across all Scenarios	FT-CASPR 'Base' Fleet	FT-CASPR Higer Band	FT-CASPR Lower Band	FT-CASPR Early Carbon	FT-CASPR No Carbon
	MW	**GWh**	**GWh**	**GWh**	**GWh**	**GWh**
2011	278	979	979	979	979	979
2012	278	1,122	1,256	1,084	1,140	1,128
2013	278	1,126	1,244	951	1,003	1,141
2014	278	1,026	782	1,180	1,142	1,016
2015	278	747	744	854	756	754
2016	745	4,252	4,272	4,298	4,243	4,269
2017	745	4,196	4,184	4,244	4,258	4,211
2018	745	4,170	4,167	4,227	4,217	4,186
2019	745	4,190	4,172	4,223	4,231	4,194
2020	745	4,184	4,189	4,239	4,260	4,194
2021	745	4,177	4,152	4,198	4,210	4,186
2022	745	4,224	4,210	4,295	4,211	4,194
2023	745	4,218	4,221	4,314	4,225	4,207
2024	745	4,252	4,219	4,307	4,241	4,221
2025	745	3,501	3,311	3,629	3,490	3,455
2026	745	3,752	3,700	3,836	3,747	3,701
2027	745	3,655	3,491	3,754	3,644	3,612
2028	745	3,761	3,652	3,842	3,758	3,706
2029	745	3,785	3,675	3,857	3,775	3,747
2030	745	3,737	3,525	3,777	3,699	3,659

c. Below is the projected mix of capacity and generation by source for Option #1 (Retrofit Big Sandy 2) under the FT-CSAPR 'Base' commodity pricing scenario.

Option 1 FT-CASPR 'Base' Fleet	KPCo Installed Capacity MW	PJM Market Firm Capacity Purchases MW	KPCo Total Thermal Generation GWh	PJM Market Purchases GWh	KPCo Contract Purchases GWh
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,108	225	8,234	260	139
2016	373	938	5,691	2,373	139
2017	1,116	178	7,809	307	139
2018	1,115	189	8,275	154	139
2019	1,119	197	7,736	341	139
2020	1,117	206	8,289	174	139
2021	1,131	206	8,297	151	288
2022	1,131	218	7,980	354	288
2023	1,131	224	6,981	828	288
2024	1,131	234	7,691	384	289
2025	1,538	0	9,144	185	288
2026	1,538	0	9,449	140	288
2027	1,538	0	9,179	299	288
2028	1,538	0	9,458	167	289
2029	1,538	0	9,254	202	288
2030	1,538	0	8,992	515	288

d. Below is the projected mix of capacity and generation by source for Option #2 (Replace Big Sandy 2 with a [Brownfield] CC build) under the FT-CSAPR 'Base' commodity pricing scenario.

Option 2 FT-CASPR 'Base' Fleet	KPCo Installed Capacity	PJM Market Firm Capacity Purchases	KPCo Total Thermal Generation	PJM Market Purchases	KPCo Contract Purchases
	MW	**MW**	**GWh**	**GWh**	**GWh**
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,108	225	8,234	260	139
2016	1,277	34	7,136	575	139
2017	1,276	18	6,935	716	139
2018	1,278	26	7,146	580	139
2019	1,286	30	6,928	789	139
2020	1,288	34	7,248	571	139
2021	1,303	35	7,237	529	288
2022	1,303	47	7,279	519	288
2023	1,303	53	6,929	797	288
2024	1,303	63	7,032	752	289
2025	1,710	0	8,615	421	288
2026	1,710	0	8,734	333	288
2027	1,710	0	8,786	387	288
2028	1,710	0	8,736	378	289
2029	1,710	0	8,633	407	288
2030	1,710	0	8,807	402	288

e. Below is the projected mix of capacity and generation by source for Option #3 (Replace Big Sandy 2 with a "CC-Repowered Big Sandy Unit 1") under the FT-CSAPR 'Base' commodity pricing scenario.

Option 3 FT-CASPR 'Base' Fleet	KPCo Installed Capacity MW	PJM Market Firm Capacity Purchases MW	KPCo Total Thermal Generation GWh	PJM Market Purchases GWh	KPCo Contract Purchases GWh
2011	1,115	0	8,280	369	58
2012	1,316	0	9,438	80	138
2013	1,317	0	7,657	807	138
2014	1,387	0	7,961	690	139
2015	1,364	0	9,090	139	139
2016	1,153	158	7,049	621	139
2017	1,152	142	6,854	766	139
2018	1,154	150	7,069	622	139
2019	1,162	154	6,848	843	139
2020	1,164	158	7,169	612	139
2021	1,179	159	7,154	569	288
2022	1,179	171	7,201	559	288
2023	1,179	177	6,844	855	288
2024	1,179	187	6,948	807	289
2025	1,586	0	8,557	421	288
2026	1,586	0	8,654	346	288
2027	1,586	0	8,720	390	288
2028	1,586	0	8,661	390	289
2029	1,586	0	8,553	424	288
2030	1,586	0	8,735	409	288

f. See attached file.

g. At this point it would be purely speculative as to when additional capacity would be required should Big Sandy Unit 2 be retrofitted and not retired. That said, based on the incremental re-investment in that unit, it would be desired that the unit could continue operation through the full 'study period' utilized in the unit disposition evaluation set forth in Mr. Weaver's direct testimony (i.e., through 2040). Hence replacement capacity for Big Sandy 2 may not be required until that point. However, any *incremental* KPCo load & demand growth could require such additional capacity to be acquired/built slightly sooner.

h. As is recognized in either Option #2 or Option #3 as identified in TABLE 1 of Mr. Weaver's testimony, replacement capacity would be required immediately upon the retirement of Big Sandy Unit 2.

i. See the response to part g. of this question.

j. See the response to part h. of this question.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Direct Testimony of Weaver, pages 31 to 48, and Exhibit SCW-4.

a. Please list each combination of commodity pricing scenarios the Company used to test the sensitivity of its "base" evaluation, e.g. "lower band" natural gas plus "early carbon", or "higher band" natural gas plus "no carbon"

b. Please provide the results of each combination of commodity pricing scenarios the Company used to test the sensitivity of its base evaluation.

RESPONSE

a. The Exhibit SCW-4 offers a matrix of the relative study period economics --as vis-a-vis the Option #1 (Big Sandy Retrofit) alternative-- of each of the other/alternative options (Option #2, #3, #4A and #4B). Each is compared based on a <u>unique</u> pricing scenario identified on TABLE 3 of Mr. Weaver's direct testimony. Comparisons occur only across a specific pricing scenario; meaning one cannot "mix-and-match" results for a particular option across one pricing scenario versus another option under a different pricing scenario. Rather, the notion would be to understand how each of the respective alternative "Options" would be impacted under the same pricing scenario (e.g., how does Option #1 compare to, say, Option #2 if both were evaluated under pricing conditions set forth "LOWER Band" commodity pricing). Then comparing these, again, relative differences across each of the 5 pricing scenarios modeled, offers a reasonable risk assessment based on this discrete outcomes from the Strategist tool.

b. See the matrix results reflected in Exhibit SCW-4 and the response to part a of this question.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Direct Testimony of Weaver, pages 31 to 48, and Exhibit SCW-4.

a. At what cumulative present worth ("CPW") would the Company consider the retrofit of Big Sandy 2 statistically indifferent to any of the other Options?

b. What is the basis for choosing that level of difference?

RESPONSE

a. The modeling performed by the Strategist tool, and results reflected in Exhibit SCW-4, offered no specific CPW valuation for purpose of determining a statistical point of indifference.

b. See response to part a.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Direct Testimony of Weaver, page 35, lines 1 to 17.

a. Please provide all assumptions and calculations, including the source workbooks in operational format, supporting the calculation of $4.49 per month.

b. Please provide the absolute levelized G-rate impact a residential customer using 1,000 kWh per month would experience under alternative option 1. Please include all assumptions and calculations, including the source workbooks in operational

c. Please provide the absolute levelized bill of a residential customer using 1,000 kWh per month for all revenue requirements excluding alternative option 1. Please include all assumptions and calculations, including the source workbooks in operational format, supporting the calculation

RESPONSE

a. See page 2 of this response.

b/c. Option 1 is the alternative used to calculate the residential customer impact of a customer using 1000 kWh as shown in the response to AG 1-28. The Company has not made any calculations at a G-rate level.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Direct Testimony of Weaver, page 37, lines 4 to 6.

a. Does Mr. Weaver agree that alternative Options 1, 2 and 3 each commit the Company to a major, front-end capital investment by 2016? If not, why not.

b. Does Mr. Weaver agree that under either of alternative Options 1, 2 and 3 the Company has little or no flexibility to respond to uncertainties in load, fuel prices, emission prices, reductions in generating technology costs or future environmental regulations from 2017 through 2040. If not, why not.

RESPONSE

a. Yes.

b. Not necessarily. The Company always has an option to change its course of action should the environment in which it is operating changes significantly. However, the Company must also ensure a reliable, adequate, and economic supply of electric power and energy. If every utility took a "wait and see" approach, no new capacity would be built. Option 4 also limits flexibility in terms of having to rely on an unpredictable market for the energy needs of its customers.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, page 39 and 40. Please explain why Mr. Weaver does not believe the Company's banding and sensitivity analyses fully address the risks he lists on page 39 line 12 through page 40 line 3.

RESPONSE

The identification of the PJM-RPM (capacity auction) construct risks identified in the cited testimony are not reflected in the AEP Fundamental Analysis group's forecast of such (PJM capacity) values, which served as the basis for the long-term Strategist economic modeling of Big Sandy disposition options.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, page 37, lines 4 to 6.

a. Does Mr. Weaver consider uncertainty in peak demand and/or annual internal retail load to be a source of economic risk through 2040? If not, why not.

b. Does Mr. Weaver consider the possibility of a major reduction in the cost of electricity from sources other than coal and natural gas to be a source of economic risk through 2040? If not, why not.

RESPONSE

a. No. See the response to Staff Item No. 73, First Set.

b. No. While the cost of certain sources of energy has decreased over time, there have been no new, low cost, non-coal/natural gas baseload technologies introduced in the recent past. Even if a new, breakthrough technology was discovered tomorrow, to commercially develop and deploy such a technology would potentially take multiple decades.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Weaver page 51, lines 15-17

a. Please explain under what circumstances an SCR unit would be required to meet the "proposed EGU MACT rulemaking"

b. Does this answer change in light of the final MATS rulemaking?

RESPONSE

a. The discussion around the cited testimony pertains to Big Sandy Unit 1, and simply suggests that, consistent with other fully-controlled AEP units burning bituminous coals in its eastern fleet, the necessary reductions in mercury emissions under the proposed EGU MACT rulemaking (now, "MATS" rules) could require the installation of both an FGD and an SCR to achieve the experienced mercury reduction co-benefits.

b. No, the mercury emission limits remain unchanged from the proposed rule, to the now final (MATS) rule, at 1.2 lb. per trillion Btu of coal heat content.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 6, lines 12 to 20 and Exhibit SCW-1.

a. Please provide all assumptions and workpapers underlying the assumed variable correlations found in Table 1-4 on page 11 of SCW-1.

b. Please explain why natural gas prices are assumed to have a negative correlation with a CO2 Emission Price/Tax, whereas coal prices have a positive correlation with a CO2 Emission Price/Tax.

c. Please explain why power prices are assumed to have a negative correlation with a CO2 Emission Price/Tax.

RESPONSE

a. See Page 2 of this response.

b. The correlations were calculated using futures prices from the Intercontinental Exchange (ICE futures exchange). The United States does not have an exchange where carbon futures are actively traded along side other commodities; it is believed that the commodities would trade in a similar manner as they do in the European system. The specific contracts were the ECX EUA (European Union allowances)and UK Natural Gas futures, and the ECX EUA and Newcastle Coal futures.

   A possible explanation for the observed market pricing is that in an environment where more coal is being consumed, increasing its cost (and decreasing the demand and price for the alternative [natural gas], more allowances must also be consumed, increasing their cost.

c. The correlations were calculated using futures prices from the ICE futures exchange. The specific contracts were the ECX EUA and UK Base Electricity futures.

A possible explanation for the market pricing is that in an environment where power prices are low, more coal will be consumed increasing the need for additional allowances.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 11 and 12, Table 1.

a. Did KPC pursue fractional ownership of any new fossil fuel generation units proposed or iscussed by other nearby utilities as referenced in those companies' IRP, CPCN, or other planning documents?

b. Did KPC make any attempt to secure partners in the construction and operation of new fossil fuel generation units?

c. Should KPC pursue Option #4A or Option #4B, would KPC preserve the possibility of installing environmental upgrades on Big Sandy Unit 1 or Big Sandy Unit 2 at some future date (e.g. 2020, 2025, or some other date) if the assumptions related to coal prices, natural gas prices, installation costs of new generators or environmental controls, energy or peak load forecasts, the price of procurement of electricity on the PJM market, carbon prices, future environmental regulations, or any other model input or inputs proved inaccurate whereby a similar analysis performed then in fact did demonstrate that installing environmental controls was at that future date more economical than constructing new natural gas generation and/or acquiring replacement market capacity and energy from the PJM markets?

RESPONSE

a. No.

b. No.

c. While plausible, preserving that option would come at a potentially significant premium. For an elaboration, please see the first paragraph of the response to Sierra Club 1-67.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 31, lines 10 to 22.

a. Has KPC commissioned any independent analysis of the potential for future "operational issues" at Big Sandy Unit 2? If so, please provide those reports.

b. For how many years was Big Sandy Unit 2 designed to operate? For how many more years does KPC expect to operate Big Sandy Unit 2 if retrofitted? If so, please provide those reports.

c. Has KPC commissioned any independent studies to determine expected future capital and operational non-fuel expenses with or without the environmental retrofits? If so, please provide those reports.

d. Has KPC commissioned any independent studies to determine the heat rates of Big Sandy Unit 1 and Big Sandy Unit 2 as they age, with or without the environmental retrofits? If so, please provide those reports.

e. Has KPC commissioned any independent studies to determine the probability of a future catastrophic failure of a component or components of Big Sandy Unit 2, resulting in a necessity to shutter the plant for an extended time period while major repairs are undergone? If so, please provide those reports.

f. Has KPC commissioned any independent studies to determine the probability of a future catastrophic failure of a component or components of Big Sandy Unit 2 which are so severe that repairing the plant would be uneconomic? If so, please provide those reports.

RESPONSE

a. No

b. There was no specific life established in the original design basis for Big Sandy Unit 2. The overall life of Big Sandy Unit 2 is a function of the many major components which make up the unit, each with their own individual service life. See KPCo's response to the Commission Staff's First Set of Data Requests Item No. 12 which explains that the service life of Big Sandy Unit 2 could approach 70 years, or through 2040.

   Using 2016 as the in-service date for the FGD, one can surmise that Big Sandy 2 could reasonably be expected to operate for approximately 25 years.

c. No

d. No

e. No

f. No

WITNESS Robert Walton

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 39 and 40.

a. Please provide an example of the price of capacity exceeding CONE "in a consistent basis" within PJM or any other electricity capacity market within the United States.

b. With respect to Options #4A and #4B, has KPC actually pursued short or long term bilateral agreements to procure capacity or energy in an effort to mitigate the "pricing uncertainty and economic risks" associated with an increase (or decrease) in the price of energy or capacity in the PJM market in future years?

RESPONSE

a. The Company is not aware of any examples of the price of capacity exceeding CONE on a consistent basis within PJM or other capacity markets, however as noted in Mr. Weaver's testimony beginning on page 38, line 8, though page 39, line 2, it should be re-iterated that, particularly, the RJM-RPM capacity construct is a relatively new, emerging market and, arguably, has not been tested by way of the reasonable prospect that significant coal-fired capacity in its footprint could be retired as a result of the known and emerging federal EPA rulemaking.

b. No. KPCo is a Member Company of the AEP-East system (Pool) which has, and continues to be, capacity and energy "long" within PJM. As indicated on Mr. Weaver's testimony on page 40, lines 11 through 18, a possible future outcome could be that a 'stand-alone' KPCo could enter into a competitive solicitation for capacity and energy depending upon the ultimate disposition outcome for Big Sandy Unit 2 (as well as Big Sandy Unit 1, as discussed on page 52, line 1, through page 53, line 15 of Mr. Weaver's testimony).

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 41 at 17-20.

a Please show analyses performed by or for KPC or AEP, or used by the Companies, that indicate that "there is an emerging concern that these [CC] facilities will soon be facing significant, time-based turbine inspections and expensive re-builds..." etc.

RESPONSE

a. There was no analysis performed. Heavy duty industrial gas turbines require major maintenance at OEM specified intervals. These intervals are typically based on the number of unit start/stop cycles or the number of operating hours, whichever comes first. For example, if an industrial gas turbine starts up and shuts down frequently, it will perform the required maintenance based on the number of startups since it would reach required starts-based maintenance milestone before it would reach any hours-based maintenance milestone. A baseload gas turbine (one that runs many hours per year) would in contrast reach the hours-based maintenance milestone first.

Large industrial gas turbine OEMs like GE and Siemens typically require major maintenance to be performed every 400 to 500 start/stop cycles or every 8,000 to 12,000 hours, whichever comes first as noted above. These maintenance cycles on an F-class gas turbines (GE 7FA or SW501F) typically cost approximately $700,000 per gas turbine to repair fuel combustion hardware (every 400 to 500 start/stop cycles or 8,000 to 12,000 hours) and $4,000,000 to $7,000,000 to inspect and repair turbine section (every 800 to 900 start/stop cycles or every 24,000 hours). In addition, the combustion and turbine hardware have a limited life in that they can only be repaired a finite number of times. Hence, after the maximum number of repairs for a given part is reached, it generally must be replaced at a fairly high cost.

As indicated in the cited testimony, as the already available/operating gas turbine based facilities age via the number of start/stop cycles or operating hours, the cost to maintain the units for safe and reliable operation can increase dramatically on an ongoing basis since many of those parts will have to replace at a fairly high cost and the ongoing repair costs can increase due to the degraded condition of the gas turbine components prior to eventual replacement.

WITNESS: Scott C Weaver, Toby thomas

Kentucky Power Company

REQUEST

Direct Testimony of Weaver, pages 43-45

a. Please confirm that "break-even" is considered "zero dollars" as stipulated on p43 line 11.

b. Is there another dollar amount (positive or negative) that the Company would consider effectively "break-even" that is not exactly "zero"? If so, what value would that be? Provide justification, if applicable.

RESPONSE

a. Yes, the break-even is essentially zero, allowing for rounding error.

b. See the response to part a.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver pages 47 and 48.

a. Does the Monte Carlo simulation and RRaR profile formulated by KPC reflect an opportunity for the company to effectively switch from Option #4A or #4B to Option #1 at any future date within the simulation should the already incurred and future "G"-cost shift considerably in Option 1's favor at any point in the model's simulated time within the given model run?

RESPONSE

a. No. First, any ultimate decision that would call for the delay or deferral of the Option #1 Big Sandy 2 DFGD retrofit (and then presumably "mothball" the unit for any interim period) would have other implications that have not been modeled. Chief among them would be the then estimated cost of the retrofit itself at any future point in time. Additional factors that would have to be considered would be the issue around the incremental on-going maintenance and equipment upkeep that would be required to keep the unit in a 'conversion-ready' mode --and the attendant recoverability of such costs--, the impact such a delay may have on existing environmental permits, etc. These implications are not known.

Second, the underlying long-term economics represented under this Monte Carlo risk analysis are performed on the basis of a full 'study period' assessment; i.e., it does not offer "interim" period results that could suggest a "change in (disposition) path."

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver page 47 line 15 through page 48 line 2

a. Please explain, in detail, why the relative economic merit of each scenario in the "discrete risk modeling results... from the Strategist-based modeling" differ so significantly from the Aurora results presented in Exhibit SCW-5.

RESPONSE

These models serve different purposes and should be considered independently. The Aurora^{XMP} model is used to measure the relative risk inherent in a resource portfolio and focuses on comparing multiple simulated results at statistically-significant points (i.e. at "50th" versus "95th" percentile results based on cumulative probability of threshold costs), and therefore does not focus on an absolute point estimate as is developed by the Strategist model.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Direct Testimony of Scott Weaver, Exhibits 1-4

a. Please provide all assumptions and workbooks, in electronic format with all calculations operational and formulae intact, used to prepare Exhibits SCW-1 through SCW-4, including output files from the Aurora model.

RESPONSE

Please see the response to KIUC Item No. 28, First Set.

WITNESS: Scott C Weaver