COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2012-00578

NOTICE OF FILING

Notice is given to all parties that the following materials have been filed into the record of this proceeding:

- The digital video recordings of the evidentiary hearing conducted July 10 – July 12, 2013 in this proceeding;

- Certifications of the accuracy and correctness of the digital video recordings;

- All exhibits introduced at the evidentiary hearing conducted July 10 – July 12, 2013 in this proceeding;

- The written logs listing, *inter alia*, the date and time of where each witness' testimony begins and ends on the digital video recordings of the evidentiary hearing conducted July 10 – July 12, 2013.

A copy of this Notice, the certifications of the digital video records, exhibit lists, and hearing logs have been served by first class mail upon all persons listed at the end of this Notice. Parties desiring electronic copies of the digital video recordings of the hearing in Windows Media format may download copies at:

http://psc.ky.gov/av_broadcast/2012-00578/2012-00578_10Jul13_Inter.asx

http://psc.ky.gov/av_broadcast/2012-00578/2012-00578_11Jul13_Inter.asx

http://psc.ky.gov/av_broadcast/2012-00578/2012-00578_12Jul13_Inter.asx

Parties wishing annotated digital video recordings may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for copies of these recordings.

The exhibits introduced at the evidentiary hearing may be downloaded at http://psc.ky.gov/pscscf/2012%20cases/2012-00578/.

Done at Frankfort, Kentucky, this 25th day of July 2013.

Linda Faulkner

Linda Faulkner
Director, Filings Division
Public Service Commission of Kentucky

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Kentucky Power Company
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Frankfort, KY 40602

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2012-00578

CERTIFICATE

I, Melinda A. Ernst, hereby certify that:

1. The attached DVD contains a digital recording of the public hearing conducted in the above-styled proceeding on **July 10, 2013**. Hearing Log and Exhibits are included with the recording on **July 10, 2013**.

2. I am responsible for the preparation of the digital recording.

3. The digital recording accurately and correctly depicts the public hearing.

4. The "Exhibit List" attached to this Certificate lists all Written Public Comments introduced at the public hearing of **July 10, 2013**.

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the public hearing of **July 10, 2013** and the time at which each occurred.

Given this _23rd_ day of July, 2013.

Melinda A. Ernst, Notary Public
State-at-Large

My Commission Expires: 02/4/2016
Notary ID 458201

Session Report - Detail

2012-00578_10Jul13

Kentucky Power Company

Date:	Type:	Location:	Department:
7/10/2013	Transfer of Control	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Mark Becker; Karl Bletzacker; Matthew Fransen; Philip Hayet; Lane Kollen; Jeffrey LaFleur; Karl McDermott; John McManus; Phillip Nelson; Greg Pauley; Scott Weaver; Ranie Wohnhas
Clerk: Melinda Ernst

Event Time	Log Event	
10:03:57 AM	Session Started	
10:03:59 AM	Chairman Armstrong	
	Note: Ernst, Melinda	Preliminary comments.
10:05:44 AM	Appearance of Counsel	
	Note: Ernst, Melinda	Quang Nguyen, Aaron Ann Cole, and Richard Raff representing the Public Service Commission (PSC).
	Note: Ernst, Melinda	Michael Kurtz representing Kentucky Industrial Utility Customers (KIUC).
	Note: Ernst, Melinda	Mark Overstreet, Ken Gish, and Hector Garcia representing Kentucky Power Company (KY Power).
	Note: Ernst, Melinda	Dennis Howard and Jennifer Black Hans representing the Office of the Attorney General (OAG).
	Note: Ernst, Melinda	Joe Childers and Shannon Fisk representing Sierra Club and Individual Intervenors.
	Note: Ernst, Melinda	Laura Kogut, McLendon-Kogus Reporting Service, LLC, will provide a transcript of the hearing for KY Power.
10:07:43 AM	Public Comments	
	Note: Ernst, Melinda	Terry Salyer, Energy Manager, representing four school systems in eastern Kentucky provided comments regarding KY Power's application.
	Note: Ernst, Melinda	Michael Hogan, Lawrence County, provided comments regarding the case being held.
	Note: Ernst, Melinda	Rocky Adkins, Kentucky Senate Majority Floor Leader, provided comments regarding the proceedings.
	Note: Ernst, Melinda	Keith Hall, Representative, Pike County, provided comments regarding the proceedings.
10:49:35 AM	Mr.Nguyen, PSC	
	Note: Ernst, Melinda	Outstanding motions include petition for confidentiality.
10:50:12 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Called as witness Gregory G. Pauley, President and Chief Operating Officer (COO) of KY Power. Mr. Pauley verified his filed testimony.
10:51:27 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the Mr. Pauley regarding his duties as president and COO of KY Power. He further questioned the witness regarding the history of KY Power's application and this case.
11:03:00 AM	OAG Exhibit 1	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, KIUC First Set of Data Requests, Dated February 6, 2013, Item No. 102, Page 1 of 1.
11:04:11 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 1.

11:07:20 AM	OAG Exhibit 2	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, KIUC's Supplemental Set of Data Requests, Dated March 8, 2013, Item No. 51, Page 1 of 1.
11:08:31 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Continued to question witness regarding his rebuttal testimony.
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 2.
11:13:55 AM	OAG Exhibit 3	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 6, 2013, Item No. 18, Page 1 of 1.
11:14:41 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned witness regarding OAG Exhibit 3. Continued to question witness regarding Aurora modeling.
11:17:01 AM	OAG Exhibit 4	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 6, 2013, Item No. 34, Page 1 of 1.
11:18:59 AM	Mr. Howard, PSC	
	Note: Ernst, Melinda	Questioned witness regarding OAG Exhibit 4. Further questioned witness regarding increase requested in KY Power's initial application.
11:22:55 AM	OAG Exhibit 5	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, Attorney General's Supplemental Set of Data Requests, Dated March 8, 2013, Item No. 12, Page 1 of 2 and miscellaneous pages attached.
11:25:28 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 5.
11:26:50 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Stated that there are handwritten notes included in OAG Exhibit 5 with the understanding that the handwritten notes are not a part of KY Power's original document.
11:27:25 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned witness regarding OAG Exhibit 5
11:31:18 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Objected to Mr. Howard's question of the witness regarding OAG Exhibit 5, Lane Kollen's testimony.
11:33:17 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 5 and the stipulation agreement between KY Power, KIUC, and Sierra Club. Continued to question the witness regarding provisions of the stipulation agreement.
11:39:46 AM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Clarified that the current case does not have a rate increase. KY Power has filed a separate application for a 23 percent rate increase.
11:40:53 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	He further questioned the witness if the "deal was off" if KY Power's application is not approved by the PSC.
	Note: Ernst, Melinda	Thanked Mr. Kurtz for the clarification and further questioned the witness regarding his rebuttal testimony.
11:48:01 AM	Session Paused	
11:55:27 AM	Session Resumed	
11:55:37 AM	OAG Exhibit 6	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, Rebuttal Testiimony of Philip J. Nelson.

11:56:39 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Directed the witness to page 5 of OAG Exhibit 6. Questioned witness regarding lines 1 through 4, Interconnection Agreement. He further questioned the witness regarding KY Power's RFP process and the procurement of services.
11:57:17 AM	Camera Lock Deactivated	
12:06:36 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Continued to question witness regarding KY Power's association with other American Electric Power (AEP) companies.
12:07:18 PM	OAG Exhibit 7	
	Note: Ernst, Melinda	In the United States District Court for the Southern District of Ohio Eastern Division, Consolidated Cases: Civil Action No. C2-99-1182, Civil Action No. C2-99-1250, Judge Edmund A. Sargus, Jr., Magistrate Judge Terence P. Kemp, etc.
12:09:19 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned witness regarding OAG Exhibit 7 and energy capacity that is available through Big Rivers Electric.
12:12:50 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned Mr. Pauley regarding the transfer of assets from Ohio Power to AEP Generation Resources. Further questioned witness regarding KY Power's application.
12:39:39 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding his early testimony, whether he was referring specifically to his current employer, KY Power, or his previous employer, AEP.
	Note: Ernst, Melinda	Questioned the witness regarding a story in the Wall Street Journal regarding KY Power's improvements to poles in lieu of storm damage that has occurred.
	Note: Ernst, Melinda	Further questioned the witness regarding the stipulation agreement and net book value.
12:46:28 PM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Stated KY Power will acquire the Mitchell Generating Station through a series of transactions and not an agreement.
12:47:24 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Further questioned the witness regarding the financial figures and information included in the application.
	Note: Ernst, Melinda	Continued to question the witness regarding KY Power's application and stipulation agreement.
1:11:22 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Questioned the witness regarding the Mitchell plants and the stipulation agreements.
1:22:35 PM	Session Paused	
2:32:45 PM	Session Resumed	
2:32:52 PM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Redirect of Witness Pauley. Questioned witness regarding similarity of the Big Sandy and Mitchell plants. Questioned further regarding his testimony this morning.
2:33:02 PM	Camera Lock Deactivated	
2:40:17 PM	Private Recording Activated	
2:47:38 PM	Session Paused	
2:47:45 PM	Session Resumed	
2:48:10 PM	Public Recording Activated	
2:49:09 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness on redirect regarding KY Power's decision to pursue the Mitchell plants.

2:50:12 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Witness Gregory Pauley excused.
2:50:41 PM	Mr. Fisk	
	Note: Ernst, Melinda	Requested the Sierra Club witness be heard out of turn. No objections.
	Note: Ernst, Melinda	Called Tim Woolf, Vice President Synapse Energy Economics, to testify.
2:51:14 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Swore in the witness, Mr. Woolf.
2:52:24 PM	Mr. Fisk, Sierra Club	
	Note: Ernst, Melinda	Questioned the witness regarding his prefiled testimony.
2:52:43 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned the witness regarding his analysis of KY Power's application and his testimony to that issue.
2:56:04 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding DSM programs and KY Power's ability to provide programs to its customers.
2:58:14 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Questioned the witness regarding market value and his prefiled testimony.
3:03:03 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding a case in Virginia involving the Mitchell Generating Station.
3:04:10 PM	Mr. Fisk, Sierra Club	
	Note: Ernst, Melinda	Questioned the witness regarding benefits of the settlement and stipulation agreement.
3:06:11 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding his comments on the benefits of the settlement and stipulation agreement.
3:07:08 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Excused the witness, Mr. Woolf.
3:07:34 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Called Phillip Hayet, Director of Consulting, J. Kennedy and Associates, to testify.
3:08:20 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Swore in the witness.
3:08:49 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Questioned the witness regarding his testimony. Witness made one correction to his testimony then verified the remainder of his testimony.
3:10:16 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned the witness regarding the analysis and review he performed to KY Power's compliance plan and his views in light of the settlement and stipulation agreement.
3:16:09 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding his testimony.
3:22:49 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Redirect of witness.
3:28:01 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Objected to Mr. Kurtz redirect of the witness.
3:29:01 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Allowed Mr. Kurtz to finish his line of questioning.
3:29:45 PM	Mr. Kurtz	
	Note: Ernst, Melinda	Continued to question the witness on redirect.
3:32:55 PM	Private Recording Activated	

3:36:09 PM	Public Recording Activated	
3:36:12 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding an analysis on the RFP for Big Sandy 1.
3:37:26 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Objected to Mr. Howard's question of the witness as it is concerning confidential information.
3:39:14 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Clarified that his question was just concerning the analysis, not the potential bidders.
3:39:20 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned the witness regarding the Mitchell plants.
3:40:31 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding additional costs incurred in purchase of the Mitchell plants.
3:46:10 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Excused the witness.
3:46:40 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Called Lane Kollen, Vice President and Principal, J. Kennedy and Associates, to testify.
3:47:24 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Swore in the witness.
3:47:46 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Verified the testimony of the witness.
3:48:31 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding the settlement and stipulation agreement.
3:52:48 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony.
3:57:12 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding AEP Generation Resources and the Ohio Commission. He further questioned legal impediments to the use of net book value.
4:09:11 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony on page 9 on KY Power's fair book value.
4:11:15 PM	Mr. Kurtz, KIUC	
	Note: Ernst, Melinda	Questioned the witness on redirect.
4:19:55 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness on redirect.
4:20:24 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding question14 of the settlement and stipulation agreement. Questioned the witness regarding net book value of Big Sandy 1.
4:24:02 PM	Private Recording Activated	
4:29:58 PM	Public Recording Activated	
4:31:27 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Excused the witness.
4:34:52 PM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Called Mark Becker, Manager Resource Planning, AEP Service Corporation, to testify.
4:35:48 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Swore in the witness.
4:36:18 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding environmental controls.

4:47:43 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Questioned the witness regarding modeling runs completed in this case.
4:50:38 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Redirect of witness.
4:51:17 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness on redirect.
4:51:53 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Closing comments.
	Note: Ernst, Melinda	Excused the witness.
4:52:03 PM	Post Hearing Data Requests	
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please update the amount of liability to be assumed by KY Power upon completion of the Mitchell Transaction. These amounts are referenced in paragraphs 38 and 42 of the Company's application.
	Note: Ernst, Melinda	(Commission Staff) Does the Mitchell Operating Agreement address a scenario where APCO obtains less than a 50 percent interest in the Mitchell Generating Station? If so, please identify how the Operating Agreement would address that scenario. If not, please identify how the Company would proceed.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please clarify the testimony of Greg Pauley as to whether the term "Company" refers to KY Power or AEP.
	Note: Ernst, Melinda	(Attorney General) Please identify any bidding process used by KY Power to obtain goods and services. If KY Power does not use a bidding process for goods and services, state as such. Please include in your answer the process for utilizing identified vendors for the provision of goods and services.
	Note: Ernst, Melinda	(Commissioner Breathitt) Please identify the current retirement age for depreciation purposes of the Mitchell Generating Station.
4:53:03 PM	Session Ended	

JAVS Exhibit List Report

2012-00578_10Jul13

Kentucky Power Company

Judge: David Armstrong; Linda Breathitt; Jim Gardner

Witness: Mark Becker; Karl Bletzacker; Matthew Fransen; Philip Hayet; Lane Kollen; Jeffrey LaFleur; Karl McDermott; John McManus; Phillip Nelson; Greg Pauley; Scott Weaver; Ranie Wohnhas

Clerk: Melinda Ernst

Name:	Description:
Kentucky Power Company Exhibit 01	Kentucky Power Company, Big Sandy Unit Disposition Analysis, Life-Cycle Study Period (30-Year, 2011-2040) Economics
OAG Exhibit 01	KPSC Case No. 2012-00578, KIUC First Set of Data Requests Dated February 6, 2013, Item No. 102, Page 1 of 1
OAG Exhibit 02	KPSC Case No. 2012-00578, KIUC's Supplemental Set of Data Requests, Dated march 8, 2013, Item No. 51, Page 1 of 1
OAG Exhibit 03	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 56, 2013, Item No. 18, Page 1 of 1
OAG Exhibit 04	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 6, 2013, Item No. 34, Page 1 of 1
OAG Exhibit 05	KPSC Case No. 2012-00578, Attorney General's Supplemental Set of Data Requests, Dated March 8, 2013, Item No. 12, Page 1 of 2 and Miscellaneous Pages
OAG Exhibit 06	KPSC Case No. 2012-00578, Rebuttal Testimony of Philip J. Nelson, May 3, 2013.
OAG Exhibit 07	In the United State District Court for the Southern District of Ohio Eastern Division, Consolidated Cases: Civil Action No. C2-99-1182, Civil Action No. C2-00-1250, Judge Edmond A Sargus, Jr., Magistrate Judge Terence P. Kemp, etc.
OAG Exhibit 09	KPSC Case No. 2011-00401, Application of KPC for Approval of its 2011 ECP, For Approval of its Amended ECR Surcharge Tariff, and for the Grant of a CPCN for the Construction and Acquistion of Related Facilities, Rebuttal Testimoeny of John M. McManus
OAG Exhibit 10	Order in KPSC Case No. 2011-00375, Joint App of LG&E and KU for a CPCN and SCC for the Construction of a CCC Turbine at the Cane Run Generating Station and the Purchase of Existing SCC Turbine Facilities from Bluegrass Gen Co, LLC in LaGrange, KY
PSC Exhibit 01	Bloomberg Businessweek Article, Politics and Policy, Obama Raises the Cost of Carbon Emissions 60 Percent, by Mark Grajem on June 20, 2013
Public Comment	Lawrence Co. Atty provided an Addendum to a Petition previously filed as Lawrence Co. Atty Exh. 01 during the hearing held May 29, 2013 in Case No. 2012-00578. Addendum consists of additional names to be added to the previously filed Petition.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)	CASE NO. 2012-00578

CERTIFICATE

We, Melinda A. Ernst, Sonya J. Harward, and Pamela J. Ayer , hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on July 11, 2013. Hearing Log, Exhibits, Exhibit List, and Witness List are included with the recording on July 11, 2013.

2. We are responsible for the preparation of the digital recording.

3. The digital recording accurately and correctly depicts the hearing.

4. The "Exhibit List" attached to this Certificate lists all exhibits introduced at the hearing of July 11, 2013.

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of July 11, 2013 and the time at which each occurred.

Given this 22nd day of July, 2013.

Melinda A. Ernst

Melinda A. Ernst, Notary Public
State-at- Large
My Commission Expires: Feb. 4, 2016

Sonya J. Harward

Sonya J. Harward (Boyd), Notary Public
State-at-Large
My Commission Expires: Aug. 25, 2013

Pamela J. Ayer

Pamela J. Ayer

JAVS **Session Report - Detail** **2012-00578_11Jul13**

Kentucky Power Company

Date:	**Type:**	**Location:**	**Department:**
7/11/2013	Transfer of Control	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner; Hearing Officer Jim Wood
Witness: Karl Bletzacker - KY Power; Matt Fransen - KY Power; John McManus - KY Power; Ranie Wohnhas - KY Power
Clerk: Pam Ayer; Melinda Ernst; Sonya Harward

Event Time	**Log Event**	
9:34:57 AM	Session Started	
9:34:59 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Called Ranie Wohnhas, Managing Director, Regulatory and Finance, KY Power, to testify.
9:36:42 AM	Chairman Armstrong	
	Note: Ernst, Melinda	Swore in the witness.
9:36:55 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony and provided modifications to three items in the testimony of the witness. Verified the testimony of the witness with those three modifications.
9:38:27 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony and future rate cases.
9:41:00 AM	Camera Lock Deactivated	
9:45:00 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Continued questioning the witness regarding his filed testimony and the settlement and stipulation agreement by line item. He further questioned the PSC's authority in light of future applications made by KY Power following the PSC's approval of the settlement and stipulation agreement.
10:36:40 AM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Objected to Mr. Howard's line of questioning.
10:37:17 AM	Chairman Armstrong	
	Note: Ernst, Melinda	Sustained Mr. Overstreet's objection.
10:37:41 AM	Mr. Overstreet	
	Note: Ernst, Melinda	Explained the witness could provide an explanation of KY Power's intentions regarding the Big Sandy and Mitchell plants in light of the settlement and stipulation agreement.
10:38:57 AM	OAG Exhibit 8	
	Note: Ernst, Melinda	KPSC Case No. 2012-00578, Commission Staff's Fifth Set of Data Requests, Order Dated June 26, 2013, Item No. 10, Attachment 1, Page 1 of 2.
10:40:09 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 8.
10:42:14 AM	Mr. Wohnhas, KY Power	
	Note: Ernst, Melinda	Responded to Mr. Howard's questions and provided details regarding OAG Exhibit 8.
10:51:30 AM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding OAG Exhibit 8 and KY Power's data request responses.
10:58:21 AM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Continued with questions for the witness regarding the settlement and stipulation agreement and future plans of KY Power.

11:00:47 AM	Session Paused	
11:18:09 AM	Session Resumed	
11:19:02 AM	Public Comments	
	Note: Ernst, Melinda	Mike Armstrong, Superintendent of Schools, Lawrence County, provided comments on the rate increase sought by KY Power.
11:19:18 AM	Camera Lock Deactivated	
11:22:25 AM	Mr Wohnhas, KY Power	
	Note: Ernst, Melinda	Clarified a point in his previous testimony to Mr. Howard's examination.
11:23:51 AM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned the witness regarding his testimony, the settlement and stipulation agreement and proposed rate increases.
11:33:50 AM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned the witness regarding his testimony this morning, the settlement and stipulation agreement, and the latest rate case filed by KY Power.
11:57:07 AM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Continued with questions for the witness.
12:16:49 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Questioned the witness regarding proceedings in Kentucky, Virginia, and West Virginia.
12:25:54 PM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Redirect of the witness regarding his testimony this morning.
12:49:02 PM	Mr. Howard, OAG	
	Note: Ernst, Melinda	Questioned the witness regarding his testimony this morning and his testimony upon redirect from Mr. Overstreet.
12:52:05 PM	Session Paused	
1:30:17 PM	Session Resumed	
1:31:15 PM	Session Paused	
2:04:25 PM	Session Resumed	
2:06:58 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Additional cross examination questions.
2:08:28 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Cross examination - Questions about cost in environmental surcharge mechanism if settlement is approved.
	Note: Ernst, Melinda	Referenced Rebuttal Testimony, page 4. Questions about Mitchell not being available in May 2015 at same price if Settlement not approved.
	Note: Ernst, Melinda	Referenced page 11, paragraph 20, of Stipulation.
2:14:53 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Follow up to question about 3 state jurisdictions.
2:16:30 PM	Mr. Overstreet, KY Power	
	Note: Ernst, Melinda	Re-direct questions.
2:17:26 PM	Mr. Wohnhas excused from the stand.	
2:17:42 PM	John McManus, KY Power Witness	
	Note: Ernst, Melinda	VP of Environmental Services, AEP Service Corp.
	Note: Ernst, Melinda	Witness takes the stand.
2:18:36 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony and provided modifications to items in the testimony of the witness. Verified the testimony of the witness with those modifications.
2:24:42 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Cross Examination of witness

2:26:54 PM	Mr. Gish, KY Power, objection	
	Note: Ernst, Melinda	Requesting copies of material of previous case being discussed for the witness to review.
2:29:55 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Referencing page 7 of the Modification, a table, under paragraph 87. Asked what the modification was.
2:31:25 PM	Mr. McManus, KY Power	
	Note: Ernst, Melinda	Referenced page 5 of the Modification, paragraph 56, definition of 'retrofit'.
2:32:13 PM	OAG Exhibit 9	
	Note: Ernst, Melinda	Rebuttal Testimony of John McManus, CN 2011-00401, dated April 16, 2012
2:33:50 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Questioned witness about OAG Exhibit 9.
2:38:18 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Cross examination of witness.
2:44:16 PM	PSC Exhibit 1	
	Note: Ernst, Melinda	Article from Bloomberg Businessweek - Politics & Policy "Obama Raises the Cost of Carbon Emissions 60 Percent" from June 20, 2013.
2:46:35 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Questioned witness about PSC Exhibit 1.
2:58:15 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Interjected to ask for date of Compliance Plan. It was given as April 2015.
2:59:19 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Continued questioning of witness.
3:01:03 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Questioned witness about Mitchell unit operation in 2040.
3:04:29 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned witness.
	Note: Ernst, Melinda	Was he involved in decision to scrub Mitchell plant instead of Big Sandy?
3:23:32 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioning continued...discussing Casper program.
3:33:42 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Redirect questions for witness.
3:37:21 PM	Mr. McManus dismissed from stand.	
3:37:56 PM	Karl Bletzacker, KY Power Witness	
	Note: Ernst, Melinda	Witness takes the stand.
	Note: Ernst, Melinda	Director Fundamental Analysis, AEP Service Corp.
3:38:37 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
3:39:00 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Cross Examination of witness, referencing Rebuttal Testimony, page 9, lines 3-12.
3:42:55 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Referencing Staff DR 4-2, attachment 1.
3:48:46 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Referencing page 9 of Rebuttal Testimony, line 11.
3:58:21 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Referenced Direct Testimony, page 12, lines 10-16.
4:00:01 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned witness.

4:02:23 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Redirect questions for witness.
4:04:25 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Follow-up question about AEP peaking.
4:05:56 PM	Mr. Bletzacker dismissed from stand.	
4:07:08 PM	Session Paused	
4:24:59 PM	Session Resumed	
4:25:05 PM	Matt Fransen, KY Power Witness	
	Note: Ernst, Melinda	Director Strategic Initiatives, AEP Service Corp.
	Note: Ernst, Melinda	Witness takes the stand.
4:25:39 PM	Camera Lock Deactivated	
4:26:19 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
4:26:54 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Cross examination of witness.
4:39:30 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questioned witness. Began with questions about value of coal plants.
4:52:51 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Questioned witness about why the year 2040 was used in modeling.
4:53:24 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Also referenced page 46 of Mr. Wolfe's testimony, lines 5, 6, and 7.
	Note: Ernst, Melinda	Questioned witness, referenced page 11 of his Rebuttal, line 9.
5:03:31 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Referencing Fransen Rebuttal Testimony, page 5, table 1.
	Note: Ernst, Melinda	Redirect questions for witness.
5:07:29 PM	Mr. Fransen, KY Power	
	Note: Ernst, Melinda	Referenced his Rebuttal Testimony, page 8, FN 2.
5:23:36 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Question concerned valuation of Big Sandy.
	Note: Ernst, Melinda	Cross Examination of witness.
5:24:32 PM	Witness Fransen dismissed from stand.	
5:25:11 PM	Session Paused	
5:27:38 PM	Session Resumed	
5:27:45 PM	Session Paused	
5:33:03 PM	Session Resumed	
5:33:07 PM	Jeffrey LeFleur, Witness for KY Power Company, takes stand.	
	Note: Ernst, Melinda	VP of Generating Assets, Appalachian Power Company
5:34:14 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Qualified and swore in Jeffrey LeFleur
5:34:34 PM	Mr. Oversteet, KY Power	
	Note: Harward, Sonya	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
5:34:55 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	PSC Attorney Cole questions LeFleur regarding reasons for retiring KY Power Units, size of units, capacity of Mitchell plant.
	Note: Ernst, Melinda	Lefleur describes tests and inspections KY Power runs on individual equipment to determine type of investment
5:42:43 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Questioned witness about book value left after costs, could Mitchell run past 30 years, Major replacement of equipment, etc. in the future,
	Note: Ernst, Melinda	Questioned witness regarding tax effecting capacity factor.

	Note: Ernst, Melinda	Questioned witness about capital investment.
5:48:15 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Question witness re: Direct Testimony, Page 4, Lines 10-14 re: higher vs. lower sulphur coal.
5:51:06 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Question re: environment impact.
	Note: Ernst, Melinda	Quesitons re: witness testimony, Page 4, lines 16-17 re:investment and upgrades in precipitators. How often inspections take place? 2-3 years.
5:53:38 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Question re: Direct testimony, Page 5, plans to build new landfill at Mitchell facility
	Note: Ernst, Melinda	Page 5 - Witness read lines into record.
	Note: Ernst, Melinda	Cost of completion? Data Request provided
5:59:00 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Rebuttal Testimony. Capacity factor poor measure of performance.
	Note: Ernst, Melinda	Questions re: Rebuttal Testimony, Page 2, lines 13-17.
	Note: Ernst, Melinda	Rebuttal Testimony, page 10, lines 1-11. Explain why KY Power did not solicit proposals. Witness - Model used was sufficient.
	Note: Ernst, Melinda	Questions re: Witness Testimony, Page 2, lines 11-13.
	Note: Ernst, Melinda	Questions re: Rebuttal Testimony - Page 3, lines 3-6. Page 3, lines 10-14 - witness reads first sentence and agrees with statement. Mitchell transfer will protect against exposure to the market
6:11:58 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Questions re: number of units. Who is responsible for Mitchell Plant? How far out do the Mitchell budgets go? All things being equal, do capital expenditure budgets increase with age of unit? Non pollution capital budgets increase during course of 30 year period? Do scrubbers and SCRs increase maintenance of rest of plant? O & M cost for Individual scrubbers? Cost of upgrading electrostatic precipitator? Landfill costs? Any other large environmental budgeted items in the Mitchell budget other than precipitators and landfill? Cost of continuous emmision monitor for mercury?
6:26:19 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Referenced Pauley's testimony (7-10-13). LaFleur's DT, Page 2, line 15-16. Why underinvestment in Big Sandy 2 in order to keep it up to date and viable? Why not put scrubbers on both plants?
6:31:57 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Direct Testimony, Page 6, Line 16. Evidence that Mitchell Units could last until 2040.
	Note: Ernst, Melinda	Questions witness. Aware of other operating agreements? Referenced Exhibit XCW4, part of Scott C. Weaver's testimony. Purpose of transfer of Mitchell Unit?
6:36:27 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	Retirment date of Amos 800 Megawatt Unit?
6:37:28 PM	Ms. Cole, PSC	
	Note: Ernst, Melinda	If acquisition of Mitchell occurs, will KY Power assume all?
6:38:11 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Assume how much of envirionment site cost? Amos Units - life of any different than Mitchell Units?
6:39:06 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Super Fund issues at Big Sandy? How is life determined in depreciation schedule, and was witness involved in decision to increase it from 2031 to 2040? Should it be longer and did witness argue for that?

6:42:12 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Super Fund related issues at Mitchell Plant? No
6:42:38 PM	Witness LeFluer Excused	
6:42:52 PM	Robert Walton, Witness for KY Power, takes stand.	
	Note: Harward, Sonya	Managing Director of Projects, AEP Service Corp.
	Note: Ernst, Melinda	Witness sworn by Chairman Armstrong.
6:43:40 PM	Mr. Gish, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
6:44:30 PM	Vice Chairman Gardner	
6:47:08 PM	Robert Walton excused	
6:47:20 PM	Phil Nelson, Witness for KY Power, takes stand.	
	Note: Harward, Sonya	Managing Director Regulatory Pricing and Analysis, AEP Service Corp.
	Note: Ernst, Melinda	Sworn in and qualified by Chairman Armstrong.
6:48:21 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
6:49:01 PM	Witness Excused	
6:49:12 PM	Karl McDermott, Witness for KY Power Company, takes stand.	
	Note: Harward, Sonya	Professor at University of Illinois Springfield
	Note: Ernst, Melinda	Sworn in and qualified by Chairman Armstrong
6:50:36 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Questioned the witness regarding his filed testimony. Verified the testimony of the witness is still correct.
6:51:31 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Direct Testimony, Page 6. Line 16.
6:52:31 PM	OAG Exhibit 10	
	Note: Ernst, Melinda	Final Order in Case No. 2011-00375
6:53:30 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Witness read highlighted sections of Page 18-19 of AOG Exhibit 10. Is the RFP process reasonable?
6:57:18 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Question relating to independent appraisal and evaluation? Reasonable for KY Power to conduct independent appraisal in addition to internal market proxy to corroborate their internal results? Did witness review Mr. Weaver's modeling of that proxy?
7:01:15 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Should utility always choose least cost option? Does KY require least cost options? (Believes it does.) Did witness question any assumptions that went into Weaver's model? Meet with Weaver? (No.) Talk to Mr. Weaver? (By phone.) How long conversation last? (Less than 1/2 day.) Review actual iterations performed? Witness believes RFP unnecessary? What market proxy did Weaver use? One proxy Weaver used was what it would cost to construct 800 megawatt cycle? Other market proxies used?
7:10:01 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Testimony, Page 11. Witness aware that AEP got a bid in this case?
7:11:16 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Cautioned witness not to reveal confidential information.
7:11:42 PM	Commissioner Breathitt	
	Note: Ernst, Melinda	Testimony, Page 11. New plant higher than this proposal.

7:12:15 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Question re: AOG Exhibit 10. RFP would not be only approach? Reasonable not to have gone with an RFP and gone with alternative method? Is Weaver's approach to determine market value reasonable compared to RFP? Opinion on using RFP to value Mitchell Plant?
7:18:16 PM	Ms. Hans, OAG	
	Note: Ernst, Melinda	Read Weaver's models? Run or review those models? Visited Big Sandy Unit 2?
7:19:29 PM	Mr. Nguyen, PSC	
	Note: Ernst, Melinda	Market proxy methodology that Weaver used is an acceptable substitute for RFP?
7:20:03 PM	Vice Chairman Gardner	
	Note: Ernst, Melinda	Did witness review how Weaver determined prices from PJM market? Was forecast for10 years and not beyond? Did witness review publications? Did witness review Weaver's second proxy - AEP construction of 800 watt plan? Questions regarding discounted cash flow.
7:25:15 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Questions re: review of Mr. Weaver's modeling process, discounted rate of cash flows.
7:26:58 PM	Witness McDermott excused	
7:28:07 PM	Session Paused	
7:33:51 PM	Session Resumed	
7:33:57 PM	Mr. Garcia, KY Power	
	Note: Ernst, Melinda	Witness Testimony confidential.
7:33:57 PM	Camera Lock Deactivated	
7:34:54 PM	Chairman Armstrong	
	Note: Ernst, Melinda	Hearing adjourned until Friday, July 12, 2013 at 12:00 p.m.
7:34:57 PM	Post Hearing Data Requests	
	Note: Ernst, Melinda	(Attorney General) Please identify the Company's anticipated costs associated with paragraph 14 of the Settlement Agreement.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please identify the potential penalties and fines arising from a hypothetical decision by the Company to operate Big Sandy Unit 2 without a retrofit beyond the MATS compliance date.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please identify the revenue difference for 2012 if the provisions set forth in paragraph 15 of the Settlement Agreement would have been in effect.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please provide the estimated Big Sandy demolition costs included in the June 28, 2013 base rate case filing.
	Note: Ernst, Melinda	(Commission Staff) Please identify the depreciation study retirement dates for Amos Units 1 and 2 (the 800 MW units).
	Note: Ernst, Melinda	(KIUC) Please provide a breakdown of page 2 of 2 of Attachment 1 to the Company's response to Staff 5-10 to show stand-alone costs of owning a 50 percent interest in the Mitchell Generating Station.
	Note: Ernst, Melinda	(Attorney General) Please provide a copy of the Company's latest audited financials.
	Note: Ernst, Melinda	(Commission Staff) Please provide the heat rate for the Glen Lynn Plant.
	Note: Ernst, Melinda	(Commission Staff) Please provide a list of non-AEP plants that are fully compliant with retirement ages in the 60's and their capacity factors.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please identify the Mitchell FGD costs that will be included in the Environmental surcharge, as described in paragraph 6 of the Settlement Agreement.

7:35:30 PM	Session Paused
11:50:27 AM	Session Ended

Exhibit List Report

2012-00578_10Jul13

Kentucky Power Company

Judge: David Armstrong; Linda Breathitt; Jim Gardner

Witness: Mark Becker; Karl Bletzacker; Matthew Fransen; Philip Hayet; Lane Kollen; Jeffrey LaFleur; Karl McDermott; John McManus; Phillip Nelson; Greg Pauley; Scott Weaver; Ranie Wohnhas

Clerk: Melinda Ernst

Name:	**Description:**
Kentucky Power Company Exhibit 01	Kentucky Power Company, Big Sandy Unit Disposition Analysis, Life-Cycle Study Period (30-Year, 2011-2040) Economics
OAG Exhibit 01	KPSC Case No. 2012-00578, KIUC First Set of Data Requests Dated February 6, 2013, Item No. 102, Page 1 of 1
OAG Exhibit 02	KPSC Case No. 2012-00578, KIUC's Supplemental Set of Data Requests, Dated march 8, 2013, Item No. 51, Page 1 of 1
OAG Exhibit 03	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 56, 2013, Item No. 18, Page 1 of 1
OAG Exhibit 04	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 6, 2013, Item No. 34, Page 1 of 1
OAG Exhibit 05	KPSC Case No. 2012-00578, Attorney General's Supplemental Set of Data Requests, Dated March 8, 2013, Item No. 12, Page 1 of 2 and Miscellaneous Pages
OAG Exhibit 06	KPSC Case No. 2012-00578, Rebuttal Testimony of Philip J. Nelson, May 3, 2013.
OAG Exhibit 07	In the United State District Court for the Southern District of Ohio Eastern Division, Consolidated Cases: Civil Action No. C2-99-1182, Civil Action No. C2-00-1250, Judge Edmond A Sargus, Jr., Magistrate Judge Terence P. Kemp, etc.
OAG Exhibit 09	KPSC Case No. 2011-00401, Application of KPC for Approval of its 2011 ECP, For Approval of its Amended ECR Surcharge Tariff, and for the Grant of a CPCN for the Construction and Acquistion of Related Facilities, Rebuttal Testimoeny of John M. McManus
OAG Exhibit 10	Order in KPSC Case No. 2011-00375, Joint App of LG&E and KU for a CPCN and SCC for the Construction of a CCC Turbine at the Cane Run Generating Station and the Purchase of Existing SCC Turbine Facilities from Bluegrass Gen Co, LLC in LaGrange, KY
PSC Exhibit 01	Bloomberg Businessweek Article, Politics and Policy, Obama Raises the Cost of Carbon Emissions 60 Percent, by Mark Grajem on June 20, 2013
Public Comment	Lawrence Co. Atty provided an Addendum to a Petition previously filed as Lawrence Co. Atty Exh. 01 during the hearing held May 29, 2013 in Case No. 2012-00578. Addendum consists of additional names to be added to the previously filed Petition.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))))))))))	CASE NO. 2012-00578

CERTIFICATE

I, Sonya J. Harward, hereby certify that:

1. The attached DVD contains a digital recording of the hearing conducted in the above-styled proceeding on July 12, 2013. Hearing Log, Exhibits, Exhibit List, and Witness List are included with the recording on July 12, 2013.

2. I am responsible for the preparation of the digital recording.

3. The digital recording accurately and correctly depicts the hearing.

4. The "Exhibit List" attached to this Certificate lists all exhibits introduced at the hearing of July 12, 2013.

5. The "Hearing Log" attached to this Certificate accurately and correctly states the events that occurred at the hearing of July 12, 2013 and the time at which each occurred.

Given this 23rd day of July, 2013.

Sonya J. Harward (Boyd), Notary Public
State-at-Large
My Commission Expires: Aug. 25, 2013

Session Report - Detail

2012-00578_12July2013

Kentucky Power Company

Date:	Type:	Location:	Department:
7/12/2013	General Rates	Public Service Commission	Hearing Room 1 (HR 1)

Judge: David Armstrong; Linda Breathitt; Jim Gardner
Witness: Joseph Karrasch - KY Power; Richard Munczinski - KY Power; Scott Weaver - KY Power
Clerk: Sonya Harward

Event Time	Log Event	
12:00:37 PM	Session Started	
12:00:41 PM	Joseph Karrasch, KY Power Witness	
	Note: Harward, Sonya	Witness was sworn in.
	Note: Harward, Sonya	Manager, Asset Investments/Renewables, AEP Service Corp.
12:01:41 PM	Mr. Garcia, KY Power	
	Note: Harward, Sonya	Direct examination of witness and confirmed testimony, with one correction that was to a confidential part of his testimony.
12:02:59 PM	Chairman Armstrong	
	Note: Harward, Sonya	Asked audience to leave if they had not signed a confidentiality consent.
12:03:24 PM	Private Recording Activated	
12:41:16 PM	Public Recording Activated	
12:41:21 PM	Mr. Garcia, KY Power	
	Note: Harward, Sonya	Continued direct examination of witness in public mode.
12:41:52 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Cross examination of witness.
12:46:08 PM	Mr. Karrasch, KY Power	
	Note: Harward, Sonya	Referenced JAK3, about how long it will take to complete certain steps of the process.
12:49:58 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Asked to go into confidential session.
12:50:14 PM	Private Recording Activated	
1:00:04 PM	Public Recording Activated	
1:00:22 PM	Camera Lock Camera 1 Activated	
1:01:37 PM	Chairman Armstrong	
	Note: Harward, Sonya	Back on public record.
1:01:40 PM	Camera Lock Deactivated	
1:01:42 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked follow-up questions to responses witness had recently given to confidential questions.
1:03:54 PM	Mr. Garcia, KY Power	
	Note: Harward, Sonya	Re-direct examination of witness.
1:07:57 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Is it typical that an RFP has less than a two-year window between RFP and when resources are needed?
1:09:48 PM	Witness, Mr. Karrasch, dismissed.	
1:09:57 PM	Scott Weaver, KY Power Witness	
	Note: Harward, Sonya	Managing Director Resource Planning and Operational Analysis, AEP Service Corp.
	Note: Harward, Sonya	Witness sworn in.
1:11:56 PM	Mr. Overstreet, KY Power	
	Note: Harward, Sonya	Direct examination of witness.

	Note: Harward, Sonya	Witness accepted all testimony as accurate after making some minor corrections to Rebuttal Testimony and Direct Testimony.
1:14:45 PM	Mr. Howard, OAG	
	Note: Harward, Sonya	Cross examination of witness.
1:17:18 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Cross examination of witness, referencing fair market value.
1:21:25 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Referenced page 5, lines 6-11, of Supplemental Testimony.
	Note: Harward, Sonya	Referenced Rebuttal Testimony, page 6, Table 1-R.
	Note: Harward, Sonya	Referenced page 9, line 1-8, of Supplemental Testimony.
1:29:32 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Referenced pages 9-11 of Rebuttal Testimony.
1:33:35 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Referenced page 39 of Rebuttal Testimony, Table 5R.
	Note: Harward, Sonya	Referenced page 36 of Rebuttal Testimony, lines 12-15.
1:45:10 PM	Chairman Armstrong	
	Note: Harward, Sonya	Confirmed that we would go into confidential session.
1:45:15 PM	Private Recording Activated	
2:02:41 PM	Session Paused	
2:24:49 PM	Session Resumed	
2:24:52 PM	Private Recording Activated	
2:49:30 PM	Public Recording Activated	
2:50:26 PM	Mr. Howard, OAG	
	Note: Harward, Sonya	Cross examination of witness in public session.
2:52:26 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Witness referenced SCW 4.
	Note: Harward, Sonya	Questioned witness in public session. Discussed modeling and environmental retrofits.
2:59:17 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Referenced Direct Testimony, page 5, about options listed here and those from CN 2011-00401.
	Note: Harward, Sonya	Witness referenced SCW 2 Exhibit of Direct Testimony in his response.
3:07:48 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Referencing SCW3.
3:09:15 PM	Mr. Weaver, KY Power	
	Note: Harward, Sonya	Witness explained the options in detail, per Vice Chairman Gardner's request.
3:28:34 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked what a Stacking Analysis is.
3:33:01 PM	Commissioner Breathitt	
	Note: Harward, Sonya	Questioned witness...follow up on some responses to questions by Vice Chairman Gardner.
3:38:40 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked question of witness.
3:40:35 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	How can Commission make decision based on confidential information?
3:41:30 PM	Mr. Overstreet, KY Power	
	Note: Harward, Sonya	Redirect about another model that Vice Chairman Gardner was asking to be run.
3:43:59 PM	Chairman Armstrong	
	Note: Harward, Sonya	Going into confidential session.
3:44:03 PM	Private Recording Activated	

3:55:07 PM	Session Paused	
4:15:14 PM	Session Resumed	
4:25:24 PM	Public Recording Activated	
4:25:26 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Referenced page 39 of Rebuttal Testimony.
	Note: Harward, Sonya	Asked additional questions of witness.
4:32:18 PM	Private Recording Activated	
4:41:07 PM	Public Recording Activated	
4:41:19 PM	Richard Munczinski, KY Power Witness	
	Note: Harward, Sonya	Senior Vice President - Regulatory Service, AEP Service Corp.
	Note: Harward, Sonya	Witness sworn in.
4:41:56 PM	Mr. Overstreet, KY Power	
	Note: Harward, Sonya	Direct examination of witness and witness confirmed testimony as still accurate.
4:42:50 PM	Mr. Nguyen, PSC	
	Note: Harward, Sonya	Cross examination of witness.
4:51:16 PM	Vice Chairman Gardner	
	Note: Harward, Sonya	Asked questions of witness.
5:00:38 PM	Commissioner Breathitt	
	Note: Harward, Sonya	Questioned witness.
5:05:23 PM	Chairman Armstrong	
	Note: Harward, Sonya	Asked witness a clarifying question about past issues/track record and how company treats its customers and this Commission.
5:10:39 PM	Mr. Overstreet, KY Power	
	Note: Harward, Sonya	Paragraph 11 of Settlement and Stipulation Agreement.
	Note: Harward, Sonya	Redirect question interjected.
5:12:24 PM	Chairman Armstrong	
	Note: Harward, Sonya	Asked the witness what the company will do for Kentucky.
5:15:56 PM	Mr. Overstreet, KY Power	
	Note: Harward, Sonya	Redirect...Witness will work with Commission on their relationship.
5:16:53 PM	Commissioner Breathitt	
	Note: Harward, Sonya	Clarification question for Mr. Overstreet.
5:17:17 PM	Post Hearing Data Requests	
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please evaluate the CPW of a resource planning alternative that includes a new construction, natural gas combined cycle facility at the Big Sandy Plant with an in-service date of 2017 (as a replacement for Big Sandy Unit 2) and the proposed natural gas conversion of Big Sandy Unit 1 with an in-service date of 2015.
	Note: Ernst, Melinda	(Vice Chairman Gardner) Please provide forecasted fundamental pricing used in the strategist modeling runs.
	Note: Ernst, Melinda	(Commissioner Breathitt) Please provide an estimate of teh net book value of a 50 percent interest in the Mitchell Generating Station for the next ten years.
5:17:44 PM	Mr. Overstreet asked for due dates.	
	Note: Harward, Sonya	Will discuss with PSC counsel after conclusion of hearing the due dates for briefs and data responses.
5:18:14 PM	Hearing adjourned.	
	Note: Harward, Sonya	Chairman Armstrong.
5:18:18 PM	Session Paused	
5:23:17 PM	Session Ended	

Exhibit List Report

2012-00578_10Jul13

Kentucky Power Company

Judge: David Armstrong; Linda Breathitt; Jim Gardner

Witness: Mark Becker; Karl Bletzacker; Matthew Fransen; Philip Hayet; Lane Kollen; Jeffrey LaFleur; Karl McDermott; John McManus; Phillip Nelson; Greg Pauley; Scott Weaver; Ranie Wohnhas

Clerk: Melinda Ernst

Name:	Description:
Kentucky Power Company Exhibit 01	Kentucky Power Company, Big Sandy Unit Disposition Analysis, Life-Cycle Study Period (30-Year, 2011-2040) Economics
OAG Exhibit 01	KPSC Case No. 2012-00578, KIUC First Set of Data Requests Dated February 6, 2013, Item No. 102, Page 1 of 1
OAG Exhibit 02	KPSC Case No. 2012-00578, KIUC's Supplemental Set of Data Requests, Dated march 8, 2013, Item No. 51, Page 1 of 1
OAG Exhibit 03	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 56, 2013, Item No. 18, Page 1 of 1
OAG Exhibit 04	KPSC Case No. 2012-00578, Attorney General Initial Set of Data Requests, Dated February 6, 2013, Item No. 34, Page 1 of 1
OAG Exhibit 05	KPSC Case No. 2012-00578, Attorney General's Supplemental Set of Data Requests, Dated March 8, 2013, Item No. 12, Page 1 of 2 and Miscellaneous Pages
OAG Exhibit 06	KPSC Case No. 2012-00578, Rebuttal Testimony of Philip J. Nelson, May 3, 2013.
OAG Exhibit 07	In the United State District Court for the Southern District of Ohio Eastern Division, Consolidated Cases: Civil Action No. C2-99-1182, Civil Action No. C2-00-1250, Judge Edmond A Sargus, Jr., Magistrate Judge Terence P. Kemp, etc.
OAG Exhibit 09	KPSC Case No. 2011-00401, Application of KPC for Approval of its 2011 ECP, For Approval of its Amended ECR Surcharge Tariff, and for the Grant of a CPCN for the Construction and Acquistion of Related Facilities, Rebuttal Testimoeny of John M. McManus
OAG Exhibit 10	Order in KPSC Case No. 2011-00375, Joint App of LG&E and KU for a CPCN and SCC for the Construction of a CCC Turbine at the Cane Run Generating Station and the Purchase of Existing SCC Turbine Facilities from Bluegrass Gen Co, LLC in LaGrange, KY
PSC Exhibit 01	Bloomberg Businessweek Article, Politics and Policy, Obama Raises the Cost of Carbon Emissions 60 Percent, by Mark Grajem on June 20, 2013
Public Comment	Lawrence Co. Atty provided an Addendum to a Petition previously filed as Lawrence Co. Atty Exh. 01 during the hearing held May 29, 2013 in Case No. 2012-00578. Addendum consists of additional names to be added to the previously filed Petition.

PUBLIC COMMENT 1

PETITION

PRINTED NAME	SIGNATURE	ADDRESS	TELEPHONE	EMAIL
John Short	John Short	109 Heron Dr. Louisa Ky	606-~~888~~ 638-9635	JFShort4410@gmail.com
Bradley Jay Nelson	Bradley J. Nelson	117 B. Rice St. Louisa, Ky.	606 939-2402	bjaynelson@yahoo.com
Steve Sloan	[illegible]	Ohio.	740-886-6820	
~~[illegible]~~				
David Pinson	David Pinson	12024 Hwy 1690 Louisa Ky	606 673 3659	dpinson88@gmail.com
Priscilla Boyd	Priscilla Boyd	12019 Hwy 1690 Louisa Ky	606 673-4644	
Bill Peters	[illegible]	302 Greenhill, Ashland	606-571-2023	
Emerson McKenzie	Emerson McKenzie	664 Saddle CR WV	304-648-5680	
Mike Conley	Mike Conley	751 Hwy 2565	606-673-8039	
William H Tucker	Wm H Tucker	1040 Shoals Branch Road	304-272-6833	pappytuck@gmail.com
Steven C Jackson	Steven Jackson	9000 Midland Trail Apt 32 Ashland Ky 41102	606-776-3330	
Donald R. Wilson	DR Wilson	222 Victoria Heights Rd Louisa, Ky 41230	606-615-0149	
Michael Pyles	Michael W. Pyles	102 Warren Rd. Huntington WV.	304-523-6564	
Ricky Brown	[illegible]	122 Timberlake Drive Louisa Ky	606-638-9853	rabrown_20@yahoo.com
Mark Staley	Mark Staley	2950 Auburn Road, Apt. D4 Huntington, WV 25704	(304) 429-4443	
Chris Scott	Chris Scott	870 Vaughn Rd Louisa KY	606-673-4224	
Rob Marcum	Rob Marcum	1014 Violet lane Louisa Ky. 41230	606-638-0761	LillyRob@BellSouth.net.
Scott N. Jent	Scott Jent	60 Orange Ln. Louisa ky	606-638-0328	

Inventory List

Mike Bond	Mike Bond	1730 HWY 1690 Louisa KY 41230	(606 673-1029)
Anthony Caudill	anthony Caudill		(606) 615-4189

Kentucky Power Co.
Big Sandy Unit Disposition Analysis
Life-Cycle Study Period (30-Year, 2011-2040) Economics

MODIFIED TO REFLECT REDUCED CAPACITY VALUE ATTRIBUTABLE TO "MITCHELL TRANSFER" OPTIONS (for 1/2014 thru 5/2015 only)

COMPARATIVE Cumulative Present Worth (CPW) of Relative KPCo "G" Revenue Requirements (2011 $)

(COST / <SAVINGS>)

	Option #1		Option #2		Option #3		Option #4		Option #5	
	RETROFIT Big Sandy Unit 2; RETIRE & REPLACE Big Sandy Unit 1 (6/2015) Retrofit BS2 with Dry (NID) FGD Technology (6/2017)		RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015 & 1/2016, respectively) Replace BS2 with "Brownfield New-Build" NG-Combined Cycle (@ Big Sandy site) (7/2017)		RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "CC-Repowered" Big Sandy Unit 1 (7/2017)		RETIRE & REPLACE Big Sandy Units 1 and 2 (6/2015) Replace with Purchased Capacity & Energy		RETIRE & REPLACE Big Sandy Unit 2 (1/2016) "Gas-Converted" Big Sandy Unit 1 (7/2015)	
	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B
	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Remaining Capacity from 20% (312-MW) Mitchell Asset Transfer (1/2014)	Remaining Capacity from (PJM) Market Purchases for 10-yrs, then new-build CC or CT(s)	Capacity from (PJM) Market Purchases for <u>5-yrs</u>, then ~700-800 MW CC and/or CT-build	Capacity from (PJM) Market Purchases for <u>10-yrs</u>, then ~700-800 MW CC and/or CT-build	Capacity from 50% (780-MW) Mitchell Asset Transfer (1/2014)	Capacity from (PJM) Market Purchases for <u>5-yrs</u>, then ~700-800 MW CC and/or CT-build

all versus...

$ Millions

("BASE") Option #6: RETIRE & REPLACE Big Sandy 1 and 2 (6/2015) with <u>50% (780-MW) Mitchell Units Ownership Transfer</u> (1/2014) plus (PJM) Market Purchases (for 10-yrs)

	#1A	#1B	#2A	#2B	#3A	#3B	#4A	#4B	#5A	#5B
BASE: "Fleet Transition-CSAPR"	469	663	327	526	402	598	376	401	(156)	223
% Relative Variance	*8.1%*	*11.4%*	*5.6%*	*9.0%*	*6.9%*	*10.3%*	*6.5%*	*6.9%*	*-2.7%*	*3.8%*
'Commodity Price Banding' Scenarios...										
2. "Fleet Transition-CSAPR: HIGHER Band"	442	810	533	899	615	982	781	869	(149)	639
3. "Fleet Transition-CSAPR: LOWER Band"	486	583	232	338	303	406	186	183	(154)	27
'Carbon/CO_2 Pricing' Scenarios...										
4. "Fleet Transition-CSAPR: No Carbon"	462	692	382	617	457	688	464	502	(168)	307
5. "Fleet Transition-CSAPR: Early Carbon (2017)"	472	626	276	438	350	509	299	311	(144)	149

Note:
-- A "POSITIVE" value above would favor the 50% Mitchell Transfer (Option #6)... a "<NEGATIVE>" value would favor the alternative option
-- Every $100 Million change in CPW is equivalent to a <u>$ 2.00 per Mwh</u> (0.200 cents/kWh) impact on <u>levelized annual</u> KPCo G-revenue requirements (2011$) over the entire affected (2016-2040) period

Additional Notes:
- o 'BASE' ("Fleet Transition-CSAPR") pricing scenario --as well as '"HIGHER Band" and "LOWER Band" pricing scenarios-- assumes carbon/CO2 pricing is effective in 2022
- o Any (short-term) "interim" requirements post-Big Sandy unit retirement dates that would *precede* the in-service date of the DFGD, or replacement CC-builds (Options #1, #2, #3) would be met w/ PJM market purchases
- o Option #1 (RETROFIT Big Sandy 2) assumes the unit would operate and recovery costs through the full study period
- o Option #2 (RETIRE & REPLACE BS2 w/ "New-Build CC") assumes a 30-year operation and capital cost recovery period for the CC in all analyses
- o Option #3 (RETIRE & REPLACE BS2 w/ "CC-Repowered BS1") assumes a 20-year operation and capital cost recovery period for the CC in all analyses (i.e., thru 2035)
- o Option #4 (Gas Convert Big Sandy 1) assumes the unit would operate and recovery capital costs for the subseqent 15 period (i.e., thru 2030)
- o Options #1, #2, #4 and #6 assume Big Sandy Unit 1 is retired 6/2015 (Option #3 assumes that unit is repowered as a CC unit; Option #5 assumes the unit is 'converted' to burn natural gas in the existing boiler)
- o <u>All</u> options analyses include KPCo's 30% purchase entitlement share of AEG's 50% portion of Rockport Units 1 and 2 (or, collectively, ~393-MW of capacity and energy)
  (i.e. resulting in effectively no relative impact on any of these Big Sandy 2 disposition analyses)
- o Big Sandy 2 "Retirement" Options #2, #3, #4, #5 and #6 also conservatively <u>exclude</u> costs associated w/ socio-economic impacts to the region
  (i.e. resulting in effectively no relative impact on any of these BS2 disposition analyses)
- o "G" Revenue Requirements established on a KPCo "stand-alone" basis and is reflective of a 'cost-optimized' resource plan necessary to achieve PJM minimum reserve margin criterion (summer peak)... Such costs being inclusive of:
  1) <u>All</u> KPCo (company-dispatched) Fuel, VOM and Emission Costs (incl. CO2); 2) on-going plant FOM; and
  3) FOM and Capital (carrying charges) on *incremental* investments (e.g. environmental retrofits on coal unit and/or new-build/repowered NG-CC capacity)

KY POWER EXHIBIT 1

Exhibit SCW-1R

TABLE 3

	(a)	(b)	(c)	(d)	(e)	(f)	(g)
(1)	**Estimated "Alternative" Capital Expenditures** [(A)]		Direct (EPC) & Indirect Cost		KPCo Prod. Capital Overhead Alloc.	TOTAL COST (*Excluding* AFUDC)	
	(Excluding AFUDC)						
(2)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(3)	Option #1: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(4)	RETROFIT Option	(C)					
(5)	**Dry (NID™) FGD** [(B)]	*788*	**$858**	**949**	**$90**	**$948**	**1,048**
(6)	*Plus: Additional Non-Recurring BS2 Environmental*						
(7)	*Costs included in Modeling (thru 2021)*		*$45*	*48*	*$5*	*$50*	*53*
(8)	*TOTAL All Major Projects*		*$903*	*997*	*$94*	*$998*	*1,102*
(9)		*Unit Capacity*					
(10)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(11)	Option #2: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(12)	REPLACEMENT Option						
(13)	**New-Build CC** *(@ BS site)*	*918*	**$1,137**	**1,077**	**$97**	**$1,234**	**1,168**
(14)		*Unit Capacity*					
(15)		*(w/Duct-Firing)*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(16)	Option #3: Big Sandy Unit 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(17)	REPLACEMENT Option						
(18)	**BS1 CC Repowering**	*802*	**$1,072**	**1,161**	**$91**	**$1,163**	**1,260**
(19)		*Unit Capacity*	Millions	$/kW Installed	Millions	Millions	$/kW Installed
(20)	Option #5: Big Sandy Unit 1	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(21)	REPLACEMENT Option	(D)			(E)		
(22)	**BS1 Gas Conversion**	*268*	**$54**	**181**	*N/A*	**$54**	**181**
(23)	*Plus: Additional Non-Recurring BS1 Environmental*						
(24)	*Costs included in Modeling (thru 2021)*		*$3*	*10*	*$0.3*	*$3*	*10*
(25)	*TOTAL All Major Projects*		*$57*	*191*	*$0.3*	*$57*	*192*
(26)		*Unit Capacity*	Millions	$/kW	Millions	Millions	$/kW
(27)	Options #1,2,3,5 & 6: Big Sandy Unit 1 or 2	*MW*	*('As-Spent' $)*	*(2011 $)*	*('As-Spent' $)*	*('As-Spent' $)*	*(2011 $)*
(28)	REPLACEMENT Option		(F)			*No AFUDC would apply*	
(29)	**Mitchell 1&2 Asset Transfer @ 20%**	*312*	**$214**	**648**	*N/A*	**$214**	**648**
(30)	**Mitchell 1&2 Asset Transfer @ 50%**	*780*	**$536**	**648**	*N/A*	**$536**	**648**
(31)	*Plus: Additional Non-Recurring Mitchell Environmental*						
(32)	*Costs included in Modeling (thru 2021), post-1/2014*						
(33)	*Mitchell 1&2 Asset Transfer @ 20%*		$37	*99*	*$4*	*$40*	*110*
(34)	*Mitchell 1&2 Asset Transfer @ 50%*		*$92*	*99*	*$10*	*$101*	*110*
(35)	*TOTAL All Major Projects*						
(36)	*Mitchell 1&2 Asset Transfer @ 20%*		*$251*	*747*	*$4*	*$255*	*758*
(37)	*Mitchell 1&2 Asset Transfer @ 50%*		*$628*	*747*	*$10*	*$637*	*758*

(A) Represents AEP EP&FS and FEL capital cost estimates utilized for modeling purposes in Strategist®

(B)"DFGD" also includes necessary landfill and associated boiler modifications

(C) Reflects an assumed ~1.5% unit derate to compensate for assumed NID-FGD parasitic load

(D) Reflects an assumed ~3.5% unit derate; also reflects all required interconnection and gas pipeline/infrastructure costs

(E) Costs estimated were already 'fully-loaded'

(F) Reflects estimated "per book" cost @ 12/31/2013

Estimated Non-Recurring Major Environmental Capital Expenditures
Associated with Emerging and Proposed U.S. EPA Rulemaking

- o Mercury and Air Toxics Standards (MATs) Rule
- o Coal Combustion Residuals (CCR) Rule
- o Clean Water Act "316(b)" Rule
- o Steam Electric Effluent Limitations Guidelines (ELG)
- o NPDES Permit Limits (Mitchell only)

Included in Strategist® KPCo-Resource Modeling for either Big Sandy or Mitchell Plants 'Options'

All Costs Exclude AFUDC
($000)

	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Option #1 (Big Sandy 2 Retrofit)											
(Excluding DFGD & Assoc. Projects)											
BS U2 Ash Waste Water Treatment System	0	0	0	781	9,621	17,336	6,934	0	0	0	34,672
BS U2 316(b)	0	0	0	17	35	178	1,157	0	0	0	1,387
BS U2 Bottom Ash Pond Reline	0	0	0	0	883	4,089	4,213	0	0	0	9,185
TOTAL	*0*	*0*	*0*	*798*	*10,539*	*21,603*	*12,304*	*0*	*0*	*0*	*45,244*

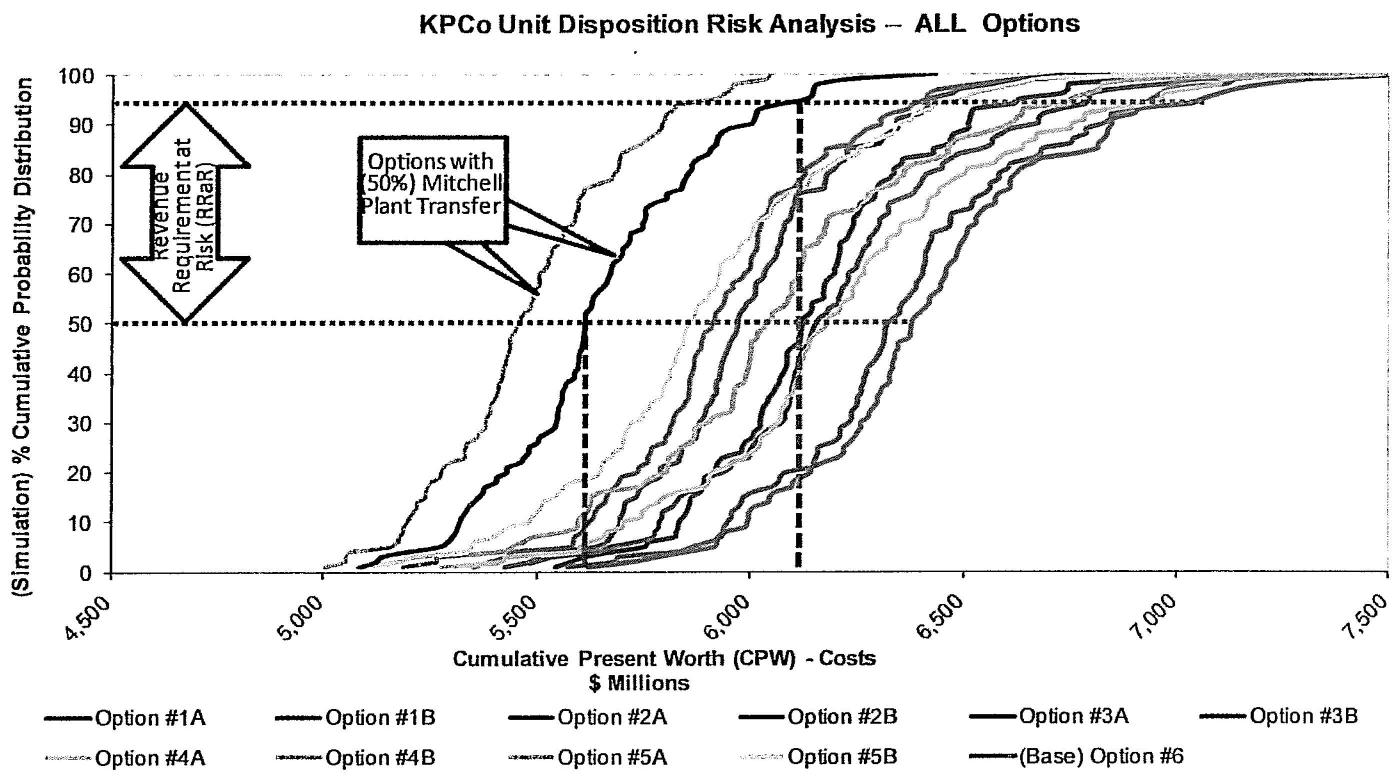
	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
Option #5 (Big Sandy 1 Convert to Gas)											
BS U1 316(b)		0	71	160	200	356	2,312	0	0	0	*3,099*

	2012 Est. *	2013	2014	2015	2016	2017	2018	2019	2020	2021	Subtotal (2014-2021)	Total
Options #1A, 2A, 3A, 5A & 6 (Mitchell Asset Transfer)												
100% of Est. Unit Costs	(A)	(A)										(A)
ML U1&2 Dry Fly Ash Conversion	29,219	54,798	20,780	0	0	0	0	0	0	0	20,780	104,796
ML U1&2 Bottom Ash Pond Reline	0	0	0	0	1,442	6,417	6,785	0	0	0	14,644	14,644
ML U1 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U1 Electro-static Precipitator Upgrades (Ph 1)	1,224	4,527	0	0	0	0	0	0	0	0	0	5,751
ML U1 316(b)	0	0	40	72	88	27	42	1,143	0	0	1,412	1,412
ML U1 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U1 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	0	5,697	19,173	0	0	24,870	24,870
ML U2 Ash Waste Water Treatment System	566	1,529	4,346	3,336	0	0	0	0	0	0	7,681	9,776
ML U2 Electro-static Precipitator Upgrades (Ph 1)	0	0	881	4,190	0	0	0	0	0	0	5,071	5,071
ML U2 316(b)	0	0	40	72	89	27	42	1,143	0	0	1,413	1,413
ML U2 ELG Waste Water Treatment System	0	0	0	1,631	4,128	6,753	7,613	0	0	0	20,125	20,125
ML U2 Electro-static Precipitator Upgrades (Ph 2)	0	0	0	0	0	12,361	10,041	0	0	0	22,402	22,402
ML U0 New Haul Road and Landfill Expansion	10,108	11,673	13,734	0	805	3,884	5,755	4,194	4,446	4,241	37,059	58,840
TOTAL	*41,683*	*74,056*	*44,166*	*14,268*	*10,680*	*36,222*	*43,588*	*25,653*	*4,446*	*4,241*	*183,264*	*299,003*
20% of TOTAL Mitchell (KPCo Options: #1A, 2A & 3A)	*8,337*	*14,811*	*8,833*	*2,854*	*2,136*	*7,244*	*8,718*	*5,131*	*889*	*848*	*36,653*	*59,801*
50% of TOTAL Mitchell (KPCo Options: #5A & 6)	*20,842*	*37,028*	*22,083*	*7,134*	*5,340*	*18,111*	*21,794*	*12,827*	*2,223*	*2,120*	*91,632*	*149,501*

* *Note: 2012 represents a full-year forecast estimate*

(A) Estimated Costs incurred prior to 1/1/2014 were incorporated into the overall "Asset Transfer" Cost

Exhibit SCW-4



	Cumulative Distribution Percentile	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	(Base) Option #6
CPW ($Millions)	50	6,123	6,380	5,912	6,153	5,972	6,325	6,178	6,037	5,458	5,856	5,612
	95	6,633	7,061	6,412	6,794	6,418	6,942	6,967	6,751	5,910	6,504	6,129
'RRaR' ($Millions)	*95th vs. 50th*	**510**	**681**	**500**	**641**	**447**	**617**	**789**	**714**	**451**	**648**	**517**
RELATIVE RRaR RANK		***4***	***9***	***3***	***7***	***1***	***6***	***11***	***10***	***2***	***8***	***5***

'RRaR' DELTAS:

(Base) Option #6 versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B	Option #5A	Option #5B	
($Millions)	***7***	***(164)***	***17***	***(124)***	***71***	***(100)***	***(271)***	***(197)***	***66***	***(131)***	
	1.4%	***-31.7%***	***3.3%***	***-23.9%***	***13.7%***	***-19.3%***	***-52.4%***	***-38.0%***	***12.8%***	***-25.3%***	

Option #5A (Also Inclusive of a '50% Mitchell 1&2 Transfer) versus...

	Option #1A	Option #1B	Option #2A	Option #2B	Option #3A	Option #3B	Option #4A	Option #4B		Option #5B	(Base) Option #6
($Millions)	*(59)*	*(230)*	*(49)*	*(190)*	***5***	*(166)*	*(337)*	*(263)*		*(197)*	*(66)*
	-13.1%	*-50.9%*	*-10.9%*	*-42.0%*	***1.1%***	*-36.8%*	*-74.7%*	*-58.2%*		*-43.6%*	*-14.6%*

Bloomberg Businessweek

PSC EXHIBIT ___/___

Politics & Policy

Obama Raises the Cost of Carbon Emissions 60 Percent

By Mark Drajem on June 20, 2013
http://www.businessweek.com/articles/2013-06-20/obama-raises-the-cost-of-carbon-emissions-60-percent

The U.S. Department of Energy's new efficiency standards for microwave ovens aren't exactly a sizzling read. Amid the dry, technical language it's easy to miss the significance of a few passages that the Obama administration tucked into the obscure regulation without consulting anyone. They amount to a sweeping change in the way the U.S. measures the effects of carbon emissions and will reverberate well beyond the kitchen.

The rule mandates cuts to "vampire" power, electricity the microwaves use in standby mode. Making them more energy-efficient will cost manufacturers and consumers about $1.3 billion over 30 years, the Energy Department says. But because the better appliances will cut carbon emissions and energy bills, the agency estimates there will be a $4.6 billion benefit to society.

The government arrived at this number by calculating what economists call the social cost of carbon, a controversial practice of trying to fix a dollar amount to the harm pollution causes society—and, conversely, to estimate the savings from cleaner fuels and technologies. With the microwave rule, the administration is changing the way it makes these calculations for all kinds of polluters.

Three years ago, federal agencies used their own formulas to calculate the social cost of carbon. The Department of Transportation pegged it at $7 per metric ton; the Environmental Protection Agency said $40. That obviously didn't make sense, says Michael Greenstone, a Massachusetts Institute of Technology professor and former White House economist. In 2010 he and a group of federal officials came up with what they considered a more accurate number for the entire federal government to use: $23.80 per metric ton. "Everybody understands that there are things you can do to make the number larger and things you can do to make the number smaller," Greenstone says. "This was the consensus judgment of a wide range of agencies with competing interests."

The provision the administration has now slipped into the microwave regulations updates this carbon cost figure with a much higher one—$38 a ton, an increase of 60 percent. Assigning a higher social cost to carbon has the effect of making coal mining, oil drilling, and other heavy industry appear more environmentally costly to regulators than before. On the flip side, it lets the administration claim greater societal benefits from its efforts to improve efficiency standards on air conditioners, vending machines, lighting fixtures, and, yes, microwave ovens.

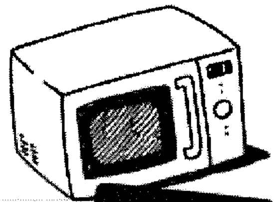
"To do this without any outside participation is bizarre," says Jeff Holmstead, a lawyer at Bracewell & Giuliani who represents power producers that depend on coal. Holmstead's clients likely have the most to fear from the change. The EPA will soon issue rules to cut power-plant emissions, which could force coal-fired plants to cut production or shut down. Because of the new social cost of carbon—which makes the plants appear to be taking a heavier toll on the environment—the rules will be easier for the administration to justify.

Yet even some liberal supporters of the administration question why it didn't open up the process to public comments. "This is a very strange way to make policy about something this important," says Frank Ackerman, an economist at Tufts University who published a book about the economics of global warming. The administration says it wasn't up to anything sneaky. The economic models federal officials use to measure the social cost of carbon have been revised to reflect damage from higher sea levels and other effects of global warming. Ari Isaacman Astles, a spokeswoman for the Office of Management and Budget, says the administration simply adopted the revised models.

Environmentalists are pushing the White House to consider the more expensive carbon costs in deciding whether to grant TransCanada (TRP) a permit for the Keystone XL pipeline—just what the fossil fuel industry wants to avoid. According to an EPA analysis, the pipeline's emissions could total 935 million metric tons over 50 years. Under the old way of accounting for emissions, the toll on society from all that pollution would have been $22 billion. Under the Obama administration's new calculus, it would come in at a far higher, and harder to defend, $36 billion.

Raising the Price of Global Warming

Obama tinkered with the way the U.S. calculates the "social costs" of carbon pollution—a change that makes the societal toll of industrial pollutants appear larger, and his own green policies appear to have greater benefits.



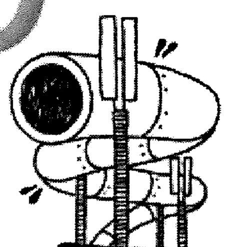
Benefit to society from making microwave ovens more efficient

Old total: $740m

BETTER

New total:

$1.2b



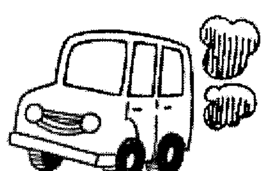
Societal cost of estimated pollution from the proposed Keystone XL pipeline

Old: $22b

WORSE

New:

$36b



Benefit to society from automobile fuel-efficiency standards

Old: $177b

BETTER

New:

$280b

DATA: DEPARTMENT OF ENERGY, ENVIRONMENTAL PROTECTION AGENCY, MICHAEL GREENSTONE/MASSACHUSETTS INSTITUTE OF TECHNOLOGY

The bottom line: *The White House raised the price it puts on emissions, making green policies look more valuable.*

Kentucky Power Company

REQUEST

Refer to page 4 lines 4-10 of Mr. Pauley's Direct Testimony. Please identify and provide a copy of all documents reviewed, relied upon, and/or prepared by Mr. Pauley to make the decision and/or communicate the decision to acquire 50% of the Mitchell units.

RESPONSE

See KIUC 1-102 Attachment 1.

WITNESS: Gregory G Pauley

OAG EXHIBIT 1

Scott C Weaver /OR4/AEPIN
06/18/2012 09:34 AM

To Gregory G Pauley/OR3/AEPIN@AEPIN, Ranie K Wohnhas/OR3/AEPIN@AEPIN
cc
bcc
Subject Fw: KPCo_resource option 're-analysis'

Please take a look at this modified strawman for the KPCo re-analysis... Does this seem reasonable to you, or are you looking for something else?

KPCo_CPCN-Resource Need 'Re-analysis' (June 2012)_Modeling Overview ppt

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

----- Forwarded by Scott C Weaver/OR4/AEPIN on 06/18/2012 09 31 AM -----

Scott C Weaver /OR4/AEPIN
06/14/2012 01:31 PM

To Gregory G Pauley/OR3/AEPIN, Ranie K Wohnhas/OR3/AEPIN
cc
Subject KPCo_resource option 're-analysis'

Gentlemen,

This is a KPCo resource option "re-analysis" straw-man I put together... I'd like to confer with you on this prior to meeting next Tues.... Now I realize that this meeting could certainly result in recommendations of yet other options --or combinations of options-- to be explored, but wanted to throw something out up-front to work off of.

For instance, I'm not sure that we'd want (or need) to continue to assess the Big Sandy "CC" replacement options (#2 and #3) that we assessed in the BS filing, but thought I'd continue to reflect for purpose of this 're-analysis' exercise. The only add'l option, not ID'd here, that I think is a non-starter would be ---as Rich alluded to--- the notion that we would seek any capacity transfers/sales from the Ohio-G *over-and-above* the "Mitchell (and Amos 3 for APCo) take" represented here.

If you have questions here, or you believe I've missed something, please give me a call.

[attachment "KPCo_Resource Requirement Study (June 2012)_Overview.ppt" deleted by Scott C Weaver/OR4/AEPIN]

Scott C. Weaver
AEP Audinet: 200-1373
Outside: (614) 716-1373

KPCo Capacity Resource Need "Re-analysis"

Resource Options

Option	*Unit Dispositions* Big Sandy 2	Big Sandy 1	Approx. Resulting KPCo Capacity Need (MW)	*BS2 Replacement*	*BS1 Replacement*	*Overall KPCo Portfolio Replacement Strategy...*
From the recent (Big Sandy) CPCN Filing (Docket No. 2011-00401)...						
#1	**Retrofit** (DFGD; 6/2016)	**Retire** (2015)	**300+**	*n/a*	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o (PJM) Capacity & Energy Market Purchases (or bi-lateral Capacity & Energy PPA) to 2025; then new-build CC capacity
#2	**Retire** (2015)	**Retire** (2015)	**1,100**	**CC (Brownfield)** (1/2016)	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o Brownfield CC (@BS), Mitsubishi 501-A 2x2x1 @ 904 MW w/ Duct-Firing o (PJM) Market Purchases (200-300 MW) (or bi-lateral PPA) to 2025; then new-build CC capacity added
#3	**Retire** (2015)	**(CC) Repower** (2015)	**300+**	**CC (BS1 Repower)** (1/2016)	**Market** (to 2025) *OR* Mitchell @20% [312-MW] (2014)	o BS1 Repower as CC, Mitsubishi 501-A 2x2x1 @ 780 MW w/ Duct-Firing o (PJM) Market Purchases (300-400 MW) (or bi-lateral PPA) to 2025; then new-build CC capacity added
~~**#4(A)**~~	~~**Retire** (2015)~~	~~**Retire** (2015)~~	~~**1,100**~~	~~**Market** (to 2020)~~	~~**Market** (to 2025)~~	~~o 5-Year (PJM) Market Purchases to 2020~~ ~~o Generic CC by 1/2020, ~900 MW w/ Duct-Firing; with additional CC capacity added in 2025~~
Other views NOT considered in that filing...						
#4	**Retire** (2015)	**Convert to Gas** (1/2016)	**800+**	**Mitchell @50% [780-MW]** (1/2014)	*n/a*	o (PJM) Capacity & Energy Market Purchases (or a bi-lateral Capacity & Energy PPA)
#5	**Retire** (2015)	**Retire** (2015)	**1,100**	**Mitchell @50% [780-MW]** (1/2014)	**Market** (to 2020)	o 5-Year (PJM) Market Purchases (or a bi-lateral PPA); then new-build CC capacity in 2020
#6	***same as #5 except...***				**Market** (to 2025)	o 10-Year (PJM) Market Purchases (or a bi-lateral PPA); then new-build CC capacity in 2025
#7	***same as #5 except...***				**Market** (to 2025)	o In lieu of 'full' ~300 MW Capacity & Energy PPA, supplement w/ "non-traditional" resources (EE/DR, VVO, Renewables)

Others?... Re-assessment of Riverside?... Other existing facilities?

(Strategist®) Modeling Parameter/Data Requirements

Modeling "G" annual revenue requirements thru 2040... discounted to current$ @ KPCo WACC

Commodity Prices, Load, CSAPR:

- Continue to use latest AEP-FA suite of L/T fundamental pricing ("Fleet Transition-CSAPR")... with suite of: "HIGHER Band", "LOWER Band", "Early (2017) Carbon" and "No Carbon" pricing scenarios.
- Continue to use latest (Fall '11) AEP-EF load & peak demand forecast for KPCo.
- Continue to model to achieve company CSAPR SO_2 unit alloc (+ Assurance Prov) limits (KPCo = 7.7k per yr., eff: 2014)

'Option-specific' parameters...

Option #1 (BS2 Retrofit):

1)In-service date remain @ 6/2016?... Later? (unit would be idled in interim)

2)Update to DFGD installed cost ($839M excl AFUDC w/ 20% contingency adder) due to compressed schedule?

3)Confirm NID removal efficiency (98.5%)... removal cost (~$300/ton SO2)

4)Confirm 'on-going' BS2 capex & FOM *(in-progress... to be forwarded by Generation)*

5)Confirm 15-year Retrofit recovery period; 25-year operating life (thru '40)

6)Confirm ultimate (BS1) CC-replacement constrained/delayed until 2025

Modeling Parameter/Data Requirements (con't)

<u>Option #2</u> (Brownfield CC):

1)In-service date remain @ 1/2016?... Later?

2)Update to CC installed cost (per S&L/Kiewet April/May '11 estimates... w/ 10% contingency adder)?

3)Confirm 30-year CC recovery period & operating life

<u>Option #3</u> (BS1 CC Repower):

1)In-service date remain @ 1/2016?... Later?

2)Updated CC-Repower cost (per S&L July/Aug '11 estimates... w/ 20% contingency adder)?

3)Confirm 20-year CC-Repower recovery period, w/ 25-year operating life (thru '40)

<u>Option #4</u> (BS1 Gas Conv; 50% Mitchell; 5 / 10 Yrs. Market for balance of need):

1)Est. capital cost of BS1 gas conversion, derate (if any), min load, heat rate (@ min & max load)

2)Mitchell "transfer value" @ 1/2014 *(in progress... to be forwarded by Reg Accounting & Tax... will include budgeted increm. Capex thru 12/2013)*

- Such value to be net of ADFIT (i.e., rate base)?... If so, will be necessary to modify levelized carrying cost rate in model

2)Confirm 'on-going' ML capex & FOM *(in-progress... to be forwarded by Generation)*

<u>Option #7</u> (50% Mitchell, 5 Yrs. Market and/or 'Alternative' Resources for balance of need):

1)___ % increase to current DSM (DR/EE) (current CLR reflects 64 MW by '20); reflect 33 MW (151 circuits @ ~$37M by '17) of increment VVO (volt/var) projects; reflect ___ (nameplate) wind resources... *i.e., similar to the "Clean Energy Standard" (proxy) portfolio reflected in the most recent APCo (Virginia) IRP*

Modeling Parameter/Data Requirements (con't)

- <u>**ALL Options**</u>: "Bilateral" (intermediated-term) capacity & energy PPA (2016-2020… or, 2016-2025):
  - AEP Generation Resources Cost-based? (slice of system?… unit-specific?)

    OR
  - Market-based? (*valuation-basis:* 'fundamentals'-based?… some other (equivalent transaction) proxy?)

Kentucky Power Company

REQUEST

Refer to the Company's response to KIUC 1-102. Please confirm that there were no other documents relied on by Mr. Pauley to make the decision and/or communicate the decision to acquire 50% of the Mitchell units. Please supplement this response if there are additional documents, such as emails or correspondence between Mr. Pauley and Mr. Patton. If none, then please so state.

RESPONSE

There were no other documents.

WITNESS: Gregory G Pauley

OAG EXHIBIT 2

Kentucky Power Company

REQUEST

Can an individual or the PSC independently recreate the Strategist ® results arrived at by the applicant?

RESPONSE

The results could be independently recreated by an individual or the PSC if they have access to the Strategist model, assuming they used the same input assumptions used by the Company.

WITNESS: Mark A Becker

OAG EXHIBIT 3

Kentucky Power Company

REQUEST

Can an individual or the PSC independently recreate the Aurora® results arrived at by the applicant?

RESPONSE

The results could be independently recreated by an individual or the KPSC if they have access to the Aurora model, assuming they used the same input assumptions used by the Company.

WITNESS: Scott C Weaver

OAG EXHIBIT 4

If the Commission authorizes the acquisition of Mitchell capacity in this proceeding, but does not condition it on flowing through to customers the entirety of the OSS margins, then the treatment of OSS margins will be an issue in the base rate case the Company plans to file in June of this year, or in any overearnings complaint case that may be filed by KIUC.

III. RATE IMPACTS OF POOL TERMINATION AND ACQUISITION OF THE MITCHELL UNITS

Q. Has the Company quantified the rate impact of the 50% Mitchell acquisition?

A. Yes. The Company estimated that the rate impact of the 50% Mitchell acquisition will be a net rate increase of $45.127 million, or 8.0% on total revenues, using 2011 as the test year. This estimate is summarized on RKW-Exhibit 4 attached to Mr. Wohnhas' Direct Testimony.

Q. Has the Company provided a more recent quantification of the rate impact of the 50% Mitchell acquisition using a 2012 test year?

A. Yes. The Company estimated that the rate impact of the 50% Mitchell acquisition will be a net rate increase of $49.5 million, or 9.9% on total revenues, using 2012 as the test year. However, the actual rate impact is almost $100 million and nearly 20%.. In order to reduce the actual rate impact, the Company "normalized" and substantially increased the test year actual generation from Big Sandy 2 and the

OAG EXHIBIT 5

Mitchell units, thus increasing the OSS margins by $10 million compared to actual. The Company also "normalized" the PJM market energy prices and substantially increased the test year actual OSS margins by $36 million. Without these "normalization" adjustments, the rate impact of acquiring 50% of the Mitchell units will be an increase of nearly 20% on total revenues. The Company provided and described this estimate and its adjustments in response to AG 2-12.

Q. Are the Company's estimates actual rate impacts?

A. No. These are estimated impacts. The Company has made no commitments that it actually will propose reductions in its revenue requirement when it files its Mitchell base rate case in June of this year to "normalize" OSS margins to reflect prior year market prices or whether it will "normalize" OSS margins to reflect improved operation of Big Sandy 2 and the Mitchell units. In my experience, it is highly unlikely that the Company will voluntarily penalize its revenue requirement by amounts of that magnitude.

Q. Is a rate increase on January 1, 2014 necessary?

A. No. The rate increase on January 1, 2014 quantified by the Company, regardless of the amount, is due solely to the unnecessarily premature acquisition of the Mitchell units prior to the Big Sandy 2 retirement. If the acquisition of replacement capacity for Big Sandy 2 is delayed until it actually is needed, there should be a rate reduction

Kentucky Power Company

REQUEST

Reference the applicant's response to AG 1-37. Please update the information.

RESPONSE

As requested in AG 1-37, the Company used 2012 data to update its 2011 analysis. Because 2012 market conditions and operations were not representative, the results of the update were historically normalized. Employing normalized 2012 data, and all else being equal, the asset transfer and termination of the pool would have produced a 9.9% increase in the Company's cost of service when compared to the costs included in the Company's rates. Further, had the Company's 2011 revenues remained constant for 2012, this would have yielded an 8.8% increase in cost of service which is even more consistent with Mr. Wohnhas' testimony using 2011 data.

There are three subparts to the analysis: change in base rates, change in fuel costs, and change in System Sales Clause revenues. Because the Company's existing base rates are the result of a "black box" settlement, the base rate subpart is premised upon the Company's cost of service as presented in Case No. 2009-00459, which the Company adjusted using best efforts to accurately reflect the settlement. The fuel and System Sales Clause values are 2012 actual cost and credit values.

Without historical normalization, and using 2012 data, costs included in base rates would have increased by $90.2 million and fuel costs would have increased $21.2 million. Increased off-system sales revenues would have reduced the cost of service by $15.5 million for a total increased cost of service of $95.9 million.

Two principal factors rendered 2012 not representative of the prior four years. First, the 2012 capacity factor for Big Sandy was significantly depressed when compared to its average capacity factor in the prior four years. Mitchell's capacity factor was depressed to a much lesser degree. This reduction in turn was driven by lower demand and significantly higher rates of scheduled outages at both stations. Second, the AEP PJM market prices for electricity were also materially lower.

The Company performed two adjustments to reflect the average historic performance of Big Sandy and Mitchell in the stand alone comparison cases.

First, the output of Big Sandy and Mitchell were modified to reflect the average hourly output of the four-year period 2008 through 2011. 2012 was excluded because the availability of both stations (Big Sandy in particular) was reduced during 2012. This adjustment to a historic average resulted in Big Sandy's capacity factor increasing from its 2012 value of 28% to the four year average of 67%. By comparison, Big Sandy's 2011 capacity factor was 68%. Mitchell's capacity factor was also increased from 55% in 2012 to its four year average of 72%. The 2011 value was 67%. In connection with the normalization, it was assumed that the incremental generation was sold in the PJM market as additional OSS. This adjustment resulted in a cost of service reduction of approximately 2% or $10 Million.

Second, the Company adjusted the hourly prices to the 2008 through 2011 four-year average AEP PJM prices. This period was used to be consistent with the period selected for the capacity factor impact. It should be noted that all but the first 8 to 9 months or so of this 48 month period followed the economic recession and the lower prices resulted from lower region wide demand. This change, based on prices prevailing in the period following the economic boom years, would have reduced the cost of service, post-OSS sharing, by another 7% or $36 million.

With this normalization of 2012 data, the Company's cost of service would have increased $49.5 million, or 9.9%, assuming the Mitchell asset transfer and the elimination of the pool.

The requested analysis and supporting documents are in AG 2-12 Attachments 1 and 2 presented in electronic format with all formulas preserved on the enclosed CD.

WITNESS: Ranie K Wohnhas

KENTUCKY POWER COMPANY

Calendar 2012

Approximate Impacts - Increase/(Decrease) vs Current Fuel Costs and Base Rates [Notes 1 and 2]

Line		2012 Actual Fuel As Defined in Kentucky	Estimated 2012 Fuel - Asset Transfers and Pool Termination - Actual 2012 Generation	Change
1	Fuel Increase/(Decrease) Cost of Service - Total Company			
2	Total Coal Generation	$86,468,500	$86,468,500	$0
3	Rockport Fuel - 151 basis	$58,571,332	$58,571,332	$0
4	AEP Pool Primary Energy Purchases	$54,377,550	$0	($54,377,550)
5	Market Power Purchases	$9,725,877	$29,915,226	$20,189,349
6	Mitchell Actual Fuel - 151 basis	$0	$105,509,422	$105,509,422
7	Less: OSS Allocation of Sources - Note 3	($38,841,826)	($89,988,058)	($51,146,232)
8	**Total Company Net Energy Requirement (NER)**	**$170,301,433**	**$190,476,423**	**$20,174,990**
9	PJM LSE Transmission Losses			$0
10	PJM Transm loss charges - LSE 4470207	$9,917,417	$10,812,318	$894,901
11	PJM Transm loss credits-LSE 4470208	($2,824,087)	($2,427,751)	$396,336
12	Total Company Fuel Cost	$177,394,764	$198,860,990	$21,466,226
13	Ky Retail Energy Allocator	98.7%	98.7%	98.7%
14	KY Jurisdictional Cost	$175,088,632	$196,275,797	$21,187,165
15	KY Jurisdictional Sales (MWh)	6,660,656	6,660,656	6,660,656
16	**Fuel Cost per MWh**	**$26.63**	**$29.86**	**$3.22**
17				

System Sales Clause (SSC) Increase/(Decrease) Cost of Service - Note 4

	Kentucky Retail Jurisdiction	2012 Actual SSC	2012 SSC - Asset Transfers with Pool Elimination	Change
1	Actual OSS Margins	($13,951,276)	($39,803,722)	($25,852,446)
2	Base Rate Credit	$15,290,363	$15,290,363	$0
3	Difference - Shortfall (Excess) vs Base Credit	$1,339,087	($24,513,359)	($25,852,446)
4	Customer Sharing	60.0%	60.0%	60.0%
5	Customer Share - SSC	$803,452	($14,708,016)	($15,511,468)
6	KY Jurisdictional Sales (MWh)	6,660,656	6,660,656	6,660,656
7	**System Sales Clause Credit per MWh**	**$0.12**	**($2.21)**	**($2.33)**
8				
9	**Total Impact - Fuel and System Sales Clause Credit**	**$26.75**	**$27.65**	**$0.89**

Notes:

1 2012 Actual column Fuel amounts represent actual values from 2012 monthly NER's and Kentucky jurisdictional fuel deferral calculations

2 Asset Transfers and Pool Elimination includes the impact of transferring 50% of Mitchell 1&2 to KPCo

3 Assumes cost assigned to OSS includes fuel and non-fuel variable costs.

4 OSS Sharing assumes continuation of current base rate credit and sharing levels

KENTUCKY POWER COMPANY
Calendar 2012
Approximate Impacts - Asset Transfer/Pool Termination Increase/(Decrease) vs Current Base Rates [Notes 1 and 2] - KY Retail Jurisdiction

Line	Kentucky Jurisdictional Amounts	Cost Reflected In Current Base Rates (PUE 2009-00459)	Estimated Base Rate Amounts - Asset Transfers and Pool Elimination	Estimated Change
2	Base Rates Increase/(Decrease) Cost of Service			
3	Net (Gain)/Expense on SO2 Emission Allowances	($322,601)	$0	$322,601
4	PJM Base Rate Admin Fees (561,565,575)	$4,404,062	$2,719,904	($1,684,157)
5	PJM Base Rate Ancillary Services and Other	$3,032,748	$2,775,982	($256,765)
6	Rockport Non Fuel Energy Costs	$39,970,517	$39,970,517	$0
7	Pool Energy Non-Fuel	$928,521	$0	($928,521)
8	Pool Capacity	$57,993,495	$0	($57,993,495)
9	LSE FTR's	($7,521,703)	($2,409,224)	$5,112,480
10	Implicit Congestion	$7,073,373	$7,602,255	$528,882
11	System Sales Clause Base Rate Credit	($15,290,363)	($15,290,363)	$0
12				
13	Emission Allowance Expense	$1,345,609	$8,627,815	$7,282,206
14	Mitchell Non-Fuel Costs			
15	Depreciation	$0	$32,532,184	$32,532,184
16	Fuel Handling	$0	$3,042,109	$3,042,109
17	Consumables and Allowances	$0	$6,349,914	$6,349,914
18	Non-Fuel O&M Expense	$0	$33,577,100	$33,577,100
19	Taxes Other Than Income	$0	$5,269,502	$5,269,502
20	Return Requirement (Pre-Tax)	$0	$57,071,128	$57,071,128
21	Subtotal Mitchell Revenue Requirement	$0	$137,841,936	$137,841,936
22				
23	**Total Base Rate Impacts**	$91,613,657	$181,838,824	$90,225,167
24				
25	**Total Estimated 2012 Change**			
26	Fuel Cost Impact			$21,187,165
27	System Sales Clause Credit Impact			($15,511,468)
28	Base Rate Impact			$90,225,167
29	**Total Impact**			$95,900,864
30	Total Ky Retail Jurisdiction Revenues			$501,036,750
31	**Percentage Change**			19.1%
32				
33				

Line	INCREMENTAL IMPACT OF BIG SANDY AND MITCHELL AT HISTORIC AVERAGE GENERATION [Note 5]			
35	Assume all incremental generation creates additional OSS	Pool MLR Share	Stand Alone	Change
36	Incremental SSC Credit	($650,091)	($10,708,486)	($10,058,395)
37	**Impact with historic Big Sandy and Mitchell Generation**			$85,842,469
38	**Percentage Change - With Historic Average Generation**			17.1%
39				
40				

Line	INCREMENTAL IMPACT OF HISTORIC AVERAGE GENERATION AND HISTORIC PRICES [Note 6]			
42	Impact of 2008-2011 Market Price	Pool MLR Share	Stand Alone	Change
43	Incremental SSC Credit	($2,348,375)	($38,683,130)	($36,334,755)
44	**Impact After Reprice OSS to 2008-2011 Average Market Price**			$49,507,714
45	**Percentage Change - Historic Average Generation with 2008-2011 Average Market Price**			9.9%

Notes:

1 2012 Actual column Fuel amounts represent actual values from 2012 monthly NER's and Kentucky jurisdictional fuel deferral calculations
2 2012 Actual column Base Rate amounts represent amounts included in base rates in final compliance cost of service from case ???
3 Normalized generation margin assumes that the Mitchell and Big Sandy generated at their 2008-2011 hourly average generation
4 OSS Sharing Assumes continuation of current sharing levels
5 Historic generation uses average output of 2008 through 2011 inclusive.
6 Historic prices based upon average 2008 through 2011 historic prices inclusive.

KENTUCKY POWER COMPANY

PCA with Asset Transfers

Expenses Increase/(Decrease)		
Allowance Expense [Note 2]	$8,741,454	IAA Impact Cal 2012.xls Tons Eqvlnt Sum wo-IAA tab
Market Energy Purchase	$29,915,226	2012 KPCo Stand Alone Energy Transaction Model.xlsx
PJM Bill (Purchased Power) LSE Portion	$18,355,270	This file - "PJM Bill" Tab
Mitchell Transfer		
Depreciation Expense	$32,994,102	This file - "KPCo ML Transfer" Tab
Fuel (net of Defd Fuel), Allowances, Chemicals	$107,028,621	This file - "KPCo ML Transfer" Tab
Consumables and Allowances	$6,440,075	This file - "KPCo ML Transfer" Tab
Non-Fuel, Non-Purch Power O&M	$34,053,854	This file - "KPCo ML Transfer" Tab
Taxes Other Than Income Taxes	$5,344,322	This file - "KPCo ML Transfer" Tab
OSS Treatment		
PCA with Asset Transfers		
OSS Margins	$34,218,485	2012 KPCo Stand Alone Energy Transaction Model.xlsx
Trading/Financial Margins	$4,236,840	2012 AEP East System OSS Margins.xls
PJM Capacity Revenues	$10,822,890	2012 PJM Capacity Allocation.xlsx
PJM Cost Allocated to OSS	($8,950,229)	This file - PJM Bill tab
Retail Sales Revenue		
FERC Account(s)	2012 Amount	
440, 442,444,445	$501,036,750	Source KPCo Retail Revenues Calendar 2012.xls

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KPCO JURISDICTIONAL ALLOCATION
Calendar 2012

Jurisdictional Factors from Case No. 2009-00459

		Kentucky Power		
		Kentucky Retail	FERC	Total
	Demand-Production	0.986	0.014	1.000
	Energy	0.987	0.013	1.000

Account	Description	Kentucky Power Kentucky Retail	FERC	Total	
101-106, 114	Utility Plant	866,733,541	12,306,561	879,040,102	
107	Construction Work in Progress	43,031,545	610,996	43,642,540	
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(275,352,538)	(3,909,671)	(279,262,209)	
121	Nonutility Property	-	-	-	
124	Other Investments	1,578,942	22,419	1,601,361	
151	Fuel Stock	28,453,928	374,773	28,828,701	
152	Fuel Stock Expenses Undistributed	731,617	9,636	741,253	
154	Plant Materials and Operating Supplies	10,193,549	144,736	10,338,285	
158.1, 158.2	Allowances	3,684,691	48,532	3,733,223	
186	Miscellaneous Deferred Debits (Property Taxes)	4,274,310	60,690	4,335,000	
190	Accumulated Deferred Income Tax (ARO)	1,773,803	25,186	1,798,989	
190	Accumulated Deferred Income Tax (PPE)	932,235	13,237	945,472	
190	Accumulated Deferred Income Tax (228 & 242)	2,245,369	31,882	2,277,251	
228.2	Accumulated Provision for Injuries and Damages	-	-	-	
230	Asset Retirement Obligations	(5,068,008)	(71,960)	(5,139,968)	
236	Taxes Accrued (Property Taxes)	(4,274,310)	(60,690)	(4,335,000)	
242	Miscellaneous Current and Accrued Liabilities (W/C)	-	-	-	
242	Miscellaneous Current and Accrued Liabilities (NSR)	(464,164)	(6,591)	(470,755)	
253	Miscellaneous Non-Current Liabilities (NSR)	(420,122)	(5,965)	(426,088)	
282	Accum. Deferred Income Taxes-Other Property (PPE)	(142,315,677)	(2,020,709)	(144,336,386)	
283	Accum. Deferred Income Taxes-Other Property (PPE)	(4,012,336)	(56,970)	(4,069,307)	
283	Accum. Deferred Income Taxes-Other (Allowances)	(1,288,335)	(18,293)	(1,306,628)	
	Total	530,438,039	7,497,799	537,935,838	
				50% of Mitchell 1 & 2	100 % of Mitchell 1 & 2
403	Depreciation Expense	32,532,184	461,917	32,994,102	65,988,203
501	Fuel (net of Defd Fuel)	105,530,220	1,498,401	107,028,621	214,057,242
502, 509	Consumables and Allowances	6,349,914	90,161	6,440,075	12,880,150
5xx, 9xx	Non-Fuel, Non-Purch Power O&M	33,577,100	476,754	34,053,854	68,107,708
408.1	Taxes Other Than Income Taxes	5,269,502	74,821	5,344;322	10,688,644

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
RATE BASE RATEMAKING ADJUSTMENTS
Calendar 2012

Account	Description	KPCo Retail Balance per Accounting	Rate Base Adjustments: ARO Adjustment	Rate Base Adjustments: Eliminate Items Not In Case No. 2009-00459	Rate Base Adjustments: Cash Working Capital Adjustment	Rate Base Adjustments: Fuel Stock Adjustment	Total Capitalization
101-106, 114	Utility Plant	866,733,541	(1,367,959)				865,365,582
107	Construction Work in Progress	43,031,545					43,031,545
108, 111, 115	Accum Prov for Depreciation & Depletion - Utility	(275,352,538)	278,105				(275,074,433)
121	Nonutility Property	-					-
124	Other Investments	1,578,942		(1,578,942)			-
151	Fuel Stock	28,453,928				(17,910,443)	10,543,485
152	Fuel Stock Undistributed	731,617					731,617
154	Plant Materials and Operating Supplies	10,193,549					10,193,549
158.1, 158.2	Allowances	3,684,691					3,684,691
186	Miscellaneous Deferred Debits (Property Taxes)	4,274,310		(4,274,310)			-
190	Accumulated Deferred Income Tax (PPE-ARO)	1,773,803	(1,773,803)				-
190	Accumulated Deferred Income Tax (PPE)	932,235					932,235
190	Accumulated Deferred Income Tax (228 & 242)	2,245,369					2,245,369
Various	Cash Working Capital	-			4,256,732		4,256,732
228.2	Accumulated Provision for Injuries and Damages	-					-
230	Asset Retirement Obligations	(5,068,008)	5,068,008				-
236	Taxes Accrued (Property Taxes)	(4,274,310)		4,274,310			-
242	Miscellaneous Current and Accrued Liabilities (W/C)	-					-
242	Miscellaneous Current and Accrued Liabilities (NSR)	(464,164)		464,164			-
253	Miscellaneous Non-Current Liabilities (NSR)	(420,122)		420,122			-
282	Accum. Deferred Income Taxes-Other Property (PPE)	(142,315,677)					(142,315,677)
283	Accum. Deferred Income Taxes-Other Property (PPE)	(4,012,336)					(4,012,336)
283	Accum. Deferred Income Taxes-Other (Allowances)	(1,288,335)					(1,288,335)
	Total	530,438,039	2,204,352	(694,656)	4,256,732	(17,910,443)	518,294,023

Adjusted rate base - KY Retail	
Total Capitalization	518,294,023
Pre-Tax Return on Capitalization (see workpaper)	11.01%
Return on Capitalization - KY Retail	57,071,128

KENTUCKY POWER COMPANY
TRANSFER 50% OF MITCHELL TO KENTUCKY POWER
KENTUCKY POWER CO RETURN ON CAPITAL CALCULATION
From Rate Case No. 2009-00459 dated June, 2010

Class of Capital	Amount (000's) ($)	% of Total (%)	Cost Rate (%)	Weighted Cost Rate (%)	Pre Tax Weighted Cost Rate of Return (%)
Long-Term Debt	$543,263,512	54.62%	6.48%	3.54%	3.54%
Preferred Stock	$0	0.00%	0.00%	0.00%	0.00%
Short Term Debt	(21,506,621)	-2.16%	2.29%	-0.05%	-0.05%
Accounts Receivable**	$46,147,086	4.64%	2.99%	0.14%	0.14%
Common Equity	$426,786,833	42.91%	10.50%	4.51%	7.38%
Total Capital	$994,690,810	100.01%		8.14%	**11.01%**

** Per Commission Order - March 31, 2003, Case No. 2002-00169.

1/ Tax Rate =	38.90%	
Tax Rate:		
Fed	35.00%	
State-KY	6.00%	
Local	0.00%	Not in effect at this time
Combined	**38.90%**	

KENTUCKY POWER COMPANY
OSS MARGIN SHARING - CALENDAR 2012

	KPCo		
	Kentucky Retail	FERC	Total
Demand-Production	$0.986	$0.014	$1.000
Energy	$0.987	$0.013	$1.000

	Kentucky Retail	Wholesale	Total
Pool Termination with Asset Transfers - Actual 2012 Generation			
Physical OSS Margins	$33,773,645	$444,840	$34,218,485
2012 Actual Financial OSS Margins	$4,181,761	$55,079	$4,236,840
PJM Capacity Revenues	$10,682,192	$140,698	$10,822,890
PJM Cost Allocated to OSS	($8,833,876)	($116,353)	($8,950,229)
Net OSS Margins	$39,803,722	$524,264	$40,327,986
Base Credit	$15,290,363	$0	$15,290,363
Remainder Available for Sharing	$24,513,359	$524,264	$25,037,623
KPCo Retained	40.00%	75.00%	
KPCo Retained Amount	**$9,805,344**	**$393,198**	**$10,198,542**
Shared Amount - Actual 2012 Generation	**$29,998,379**	**$131,066**	**$30,129,445**

Kentucky Power Company
2012 Off-System Sales Revenues

Month	Net Revenue Level	Base Level	Difference
Jan-12	1,341,487	528,886	812,601
Feb-12	873,897	335,167	538,730
Mar-12	879,707	1,530,489	(650,782)
Apr-12	737,801	1,371,521	(633,720)
May-12	1,050,028	1,307,472	(257,444)
Jun-12	1,291,406	767,124	524,282
Jul-12	2,483,188	616,234	1,866,954
Aug-12	1,287,658	2,136,652	(848,994)
Sep-12	1,210,409	1,850,577	(640,168)
Oct-12	1,158,991	1,739,665	(580,674)
Nov-12	573,454	1,538,455	(965,001)
Dec-12	1,063,250	1,568,121	(504,871)
Total	**13,951,276**	**15,290,363**	**(1,339,087)**

Customer Share	14,486,911
AEP Share	(535,635)
	13,951,276

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

The Application Of Kentucky Power Company For: (1) A Certificate Of Public Convenience And Necessity Authorizing The Transfer To The Company Of An Undivided Fifty Percent Interest In The Mitchell Generating Station And Associated Assets; (2) Approval Of The Assumption By Kentucky Power Company Of Certain Liabilities In Connection With The Transfer Of The Mitchell Generating Station; (3) Declaratory Rulings; (4) Deferral Of Costs Incurred In Connection With The Company's Efforts To Meet Federal Clean Air Act And Related Requirements; And (5) For All Other Required Approvals And Relief	) Case No. 2012-00578

REBUTTAL TESTIMONY
OF
PHILIP J. NELSON

May 3, 2013

OAG EXHIBIT 6

VERIFICATION

The undersigned, PHILIP J. NELSON being duly sworn, deposes and says he is Managing Director, Regulatory Pricing and Analysis for American Electric Power, that he has personal knowledge of the matters set forth in the forgoing testimony and that the information contained therein is true and correct to the best of his information, knowledge, and belief.

PHILIP J. NELSON

STATE OF OHIO)
) CASE NO. 2011-00578
COUNTY OF FRANKLIN)

Subscribed and sworn to before me, a Notary Public in and before said County and State, by Philip J. Nelson, this the 1st day of May 2013.

Ann Dawn Clark
Notary Public

Ann Dawn Clark
Notary Public-State of Ohio
My Commission Expires
November 16, 2015

My Commission Expires: November 16, 2015

REBUTTAL TESTIMONY OF
PHILIP J. NELSON, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2012-00578

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF PHILIP J. NELSON ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Philip J. Nelson. My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. PLEASE INDICATE BY WHOM YOU ARE EMPLOYED AND IN WHAT CAPACITY.

A. I am employed as Managing Director of Regulatory Pricing and Analysis in the Regulatory Services Department of American Electric Power Service Corporation ("AEPSC"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP"). AEP is the parent company of Kentucky Power Company ("Kentucky Power").

II. BACKGROUND

Q. PLEASE BRIEFLY DESCRIBE YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I graduated from West Liberty University in 1979 receiving a Bachelor of Science Degree in Business Administration, majoring in accounting. In 1979, I was employed by Wheeling Power Company, an affiliate of AEP, in the Managerial Department. At Wheeling Power, I was responsible for rate filings with the Public Service Commission of West Virginia ("PSC"), for resolving customer complaints made to the PSC, as well as for preparation of the Company's operating budgets and capital forecasts. In 1996, I transferred to the AEP-West Virginia State Office in Charleston, West Virginia as a senior rate analyst. In 1997, I transferred to AEPSC as a senior rate consultant in the Energy Pricing and Regulatory Services Department, with my primary responsibility being the oversight of Ohio Power Company's ("OPCo") and Columbus Southern Power's ("CSP") Electric Fuel Component ("EFC") filings. In 1999, I transferred to the Financial Planning Section of the Corporate Planning and Budgeting Department where I helped prepare AEP financial forecasts. I held various positions in the Corporate Planning and Budgeting Department until my transfer to Regulatory Services in February, 2010.

Q. **WHAT ARE YOUR RESPONSIBILITIES AS MANAGING DIRECTOR OF REGULATORY PRICING AND ANALYSIS?**

A. My department supports regulatory filings across the AEP system in the areas of cost of service, rate design, cost recovery trackers and tariff administration. It also provides expert witness testimony on AEP's east and west power pools as well as technical advice and support for power settlements and performs financial analysis of changes to AEP's generation fleet. In addition, my department provides support and filing of generation and transmission formula rate contracts.

Q. **HAVE YOU EVER SUBMITTED TESTIMONY AS A WITNESS BEFORE A REGULATORY COMMISSION?**

A. Yes. I have testified before the Virginia State Corporation Commission and the Public Service Commission of West Virginia on behalf of Appalachian Power

Company ("APCo"), before the Public Service Commission of West Virginia on behalf of Wheeling Power Company, before the Indiana Utility Regulatory Commission on behalf of Indiana Michigan Power Company and before the Public Utilities Commission of Ohio ("PUCO") on behalf of CSP and OPCo.

III. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. The purpose of my testimony is to address KIUC witness Kollen's incorrect contention that during the period from January 1, 2014 through May 31, 2015, AEP would double recover certain costs if the proposal to transfer a 50% ownership interest in Mitchell plant to Kentucky Power is approved.

Q. WHAT EXHIBITS ARE YOU SPONSORING IN THIS PROCEEDING?

A. I am sponsoring Exhibit PJN-1R which provides the KIUC response in this proceeding to Staff's First Request for Information No. 6 referred to in this testimony.

IV. OHIO ESP AND CAPACITY CASES

Q. DID YOU PARTICIPATE IN THE OHIO PROCEEDINGS WHICH ESTABLISHED A COST-BASED CAPACITY CHARGE FOR OPCO[1] RETAIL CUSTOMERS WHO CHOOSE AN ALTERNATIVE SUPPLIER?

A. Yes. In response to an information request from the KYPSC Staff to KIUC, the KIUC references my testimony in Cases Nos. 11-346-EL-SSO et. al. ("ESP Case") and 10-

[1] On December 31, 2011, CSP merged into OPCo. All references to OPCo in this testimony refer to CSP and OPCo collectively.

2929-EL-UNC ("Capacity Case") and suggests that the Ohio testimony somehow supports KIUC's position that there is a double recovery of the Mitchell costs. My testimony and the testimony of Dr. Pearce in the Ohio cases do not in any manner support this contention. I have attached the KIUC's data response to this testimony for reference as Exhibit PJN-1R.

Q. PLEASE PROVIDE THIS COMMISSION WITH THE NECESSARY BACKGROUND ON THE OHIO PROCEEDINGS SO THAT IT CAN PUT THE PROPER CONTEXT TO THE ISSUE RAISED BY KIUC WITNESS KOLLEN IN HIS TESTIMONY ON PAGES 22 AND 23.

A. Ohio has been moving, in fits and starts, for a number of years to a competitive structure for electric generation service. More recently, the PUCO has clearly directed OPCo and other utilities in the state to move more quickly to a competitive market structure. This has involved complicated and lengthy regulatory proceedings and has resulted in a short transition period for OPCo to completely separate its transmission and distribution business from the competitive generation business. As part of this transition, the issue of an appropriate capacity charge to Competitive Electric Retail Service ("CRES") providers was hotly contested. CRES providers serve retail customers that choose to receive their generation service from a supplier other than the incumbent utility. Because of capacity commitments made during the period of more regulated structure in Ohio, OPCo charges CRES providers for the capacity OPCo makes available for customers who choose a CRES provider during a transition period ending May 31, 2015.

Also, and most important to this Commission, the changes in Ohio were a contributor to the termination of the current Interconnection Agreement ("Pool Agreement") and are the reason that a 50% interest in the Mitchell units is available to transfer to Kentucky Power.

Q. PLEASE BRIEFLY DESCRIBE THE DEVELOPMENT OF THE OHIO CAPACITY CHARGE?

A. The Ohio capacity charge to CRES providers was created to reimburse OPCo for the use of its capacity in serving retail customers that are no longer receiving generation service directly from OPCo. The CRES providers are using OPCo's capacity since OPCo has already committed to providing that capacity in PJM for all its retail customers including those that are now served by a CRES provider. Therefore, a CRES provider has no obligation to supply its own capacity in PJM, but can rely on and purchase that capacity from OPCo through May 31, 2015. The capacity charge was developed based on a cost of service "formula rate" approach that has been used in the development of firm wholesale rates charged to co-ops and municipalities that purchase generation service. The costs and revenues (credits) used in the formula rate are taken from FERC Form 1 data and is typically updated annually. This formula rate concept was proposed by OPCo to the PUCO and FERC to develop the proper capacity charge to CRES providers for their use of OPCo's capacity to serve OPCo retail customers that choose another generation supplier. The PUCO generally used this method to develop the capacity charge stated in its Capacity Case and ESP Case orders.

Q. **IS THERE A DOUBLE RECOVERY OF MITCHELL COSTS THAT OCCURS THROUGH THE CAPACITY RATE APPROVED BY THE PUCO AND THE TRANSFER OF THE MITCHELL UNITS TO KENTUCKY POWER AND APCO FROM OPCO EFFECTIVE JANUARY 1, 2014?**

A. No. As I explain below, the capacity charge developed in Ohio provides compensation to OPCo for the cost of capacity used to serve <u>retail</u> customers in Ohio. The recovery of capacity costs from Ohio retail customers does not provide any revenues for replacement of the <u>wholesale</u> sales that will be lost from termination of the Pool Agreement and, importantly, does not overlap at all with the costs that Kentucky Power's customers will pay as a result of the transfer of the Mitchell units effective January 1, 2014.

V. <u>EVIDENCE SHOWING MR. KOLLEN'S TESTIMONY IS INACCURATE</u>

Q. **KIUC'S RESPONSE STATES THAT OPCO'S FORMULA CAPACITY CHARGE CALCULATION STARTS WITH ITS PLANT IN SERVICE, INCLUDING THE MITCHELL UNITS. IS THIS PART OF ITS RESPONSE ACCURATE?**

A. Yes, but the key word is "starts". They have ignored the fact that included in the development of the PUCO determined capacity charge was a credit to the cost of service ("Pool Credit") for capacity sold by OPCo to the other members of the Pool Agreement. As I explain in more detail later, there is no double recovery as claimed by Mr. Kollen because the PUCO-determined Ohio capacity charge was not designed nor approved as a means to recover all of the generation capacity costs of OPCo;

rather it recovers only the capacity cost associated with the capacity necessary to serve retail customers. The Pool Credit reduces the retail capacity charge determined by the PUCO and reflects the fact that a portion of OPCo's capacity costs are being recovered from the other parties to the Pool Agreement.

Q. WHY DOES THE DEVELOPMENT OF THE RETAIL CAPACITY CHARGE USING THE POOL CREDIT ELIMINATE ANY DOUBLE RECOVERY?

A. As this Commission is aware, the Pool Agreement terminates effective January 1, 2014. Therefore, the Pool Agreement capacity revenue provided to OPCo does not continue past December 31, 2013. The Pool Agreement payments received by OPCo are not specifically for the Mitchell units, they are compensation to OPCo for the significant portion of its generation capacity that it sells to its affiliates, including Kentucky Power. OPCo's Pool Credit was incorporated in the PUCO-determined capacity rate charged to CRES providers, reducing the Ohio capacity charge. Therefore, the retail capacity rates represent the netting of the credit and charge, and thus do not provide full compensation for all of OPCo's capacity. Instead the retail capacity rates provide only the amount needed to serve Ohio retail customers and do not replace lost wholesale revenue.

Q. CAN YOU DEMONSTRATE THAT THE POOL AGREEMENT CAPACITY CREDIT WAS IN FACT USED BY THE PUCO TO REDUCE THE CAPACITY CHARGE IT APPROVED IN THE CASES CITED BY MR. KOLLEN?

A. Yes, the $401 million in Pool Credit is clearly evident in the record in these cases and it was not disputed by any party to the cases, including the Ohio Energy Group

("OEG"), since it reduced the capacity charge for retail customers served by CRES providers. One specific reference I can point to is on page 4 of my rebuttal testimony filed May 11, 2012 in the Capacity Case where I provided the value of the Pool Credit and the amount by which it lowers the Ohio retail capacity charge.

In addition to the Pool Credit, an energy credit also reduced the capacity charge approved by the PUCO. This energy credit included the energy sales made from the Mitchell units. When the Mitchell units are transferred and the Pool Agreement ends, the energy credit would be reduced and the Pool Credit will be zero. This would result in a higher Ohio retail capacity charge all else being equal. The off-set to the end of the Pool Credit and energy credit, is the elimination of the Mitchell (and Amos 3) expenses that would no longer be on OPCo's books after the transfer of the units. These increases and reductions in the PUCO-determined capacity charge, if re-calculated on January 1, 2014, would in all likelihood result in a higher capacity charge, but there is no double recovery as suggested by KIUC witness Kollen.

Q. WILL THE PUCO-DETERMINED CAPACITY CHARGE BE UPDATED AFTER THE POOL AGREEMENT TERMINATES AS PROPOSED BY OPCO IN ITS FILING?

A. No. The PUCO did not accept the proposal for a formula rate to be updated annually, so the capacity charge is fixed for the entire transition period and, therefore, even though the Pool Credit and energy credits for the transferred units end effective January 1, 2014, they remain as a permanent reduction to the capacity charge to be charged in Ohio for the January 1, 2014 through May 31, 2015 transition period, thus eliminating any potential for double recovery because, as I discuss below, the Pool Credit is a good proxy for the assets being transferred.

Q. DID OPCO PREPARE A CALCULATION OF THE CAPACITY CHARGE WITHOUT THE MITCHELL UNITS?

A. No. However, I am confident that if the PUCO-determined capacity charge was updated after the transfer of the Mitchell units and the termination of the Pool Agreement, the updated capacity charge would in fact be higher than the capacity charge approved by the PUCO. In support of this conclusion I can point to Exhibit PJN-3 attached to my direct testimony filed March 30, 2012 in the ESP Case. This exhibit shows that OPCo sold about 2500 MW to other Pool Agreement members, which is comparable to the capacity of the Mitchell and Amos units being transferred to Kentucky Power and APCo. The Pool Credit of $401 million associated with the 2500 MW sold to other Pool Agreement members, which reduced the PUCO-determined capacity charge, exceeds the carrying cost of 100% of the Mitchell units and OPCo's share of Amos Unit 3.

VI. PUCO APPROVED POOL MODIFICATION RIDER

Q. GRANTED THAT THE PUCO APPROVED CAPACITY CHARGE DOES NOT COMPENSATE OPCO FOR ITS LOST POOL AGREEMENT REVENUE, THE PUCO APPROVED A SEPARATE RIDER PROVIDING OPCO THE POTENTIAL FOR SUCH RECOVERY, DID IT NOT?

A. Yes. However, the rider would only apply if the Mitchell and Amos unit transfers were not approved. This was in recognition of the fact that if all OPCo generating units were to be retained for OPCo's retail customers' benefit, then the rider should compensate OPCo for its lost wholesale (Pool Agreement) revenue, since the PUCO's approved capacity charge and other retail rates did not. If OPCo were permitted to transfer the units, then it would no longer have the need to recover the costs of the transferred units thus reducing or eliminating the need for the rider charge. Approval of a separate rider charge only in the event that the assets are not transferred is further evidence, again ignored by Mr. Kollen, that the current capacity charge mechanism does not allow for double recovery.

VII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY?

A. The evidence presented in the PUCO cases cited by KIUC in its response to Commission Staff's First Request for Information No. 6, does not support its contention that there would be a double recovery of Mitchell costs during the 17-month period from January 1, 2014 through May 31, 2015. In fact an examination of the record in the cases cited by KIUC refutes this contention. Clearly with the termination of the Pool Agreement, OPCo is losing substantial capacity revenue that is not being recovered by retail customers in Ohio, so there is no double recovery. The KIUC's accusation is not supported by any evidence they have offered.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes it does.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	**Case No. 2012-00578**

KIUC'S RESPONSES TO
COMMISSION STAFF'S
FIRST REQUEST FOR INFORMATION

6. Refer to page 22, lines 6 through 8 of the Kollen Testimony. Provide support for the statement, "Ohio Power Company will continue to receive a form of cost- based recovery for the Mitchell units through May 31, 2015.

RESPONSE:

Please refer to the PUCO Orders in Case Nos. 10-2929 and 11-346, which are available on the PUCO website. In addition, please refer to the testimony of AEP Ohio Power Company witnesses Kelly D. Pierce in Case No. 10-2929 and Phillip J. Nelson in Case No. 11-346 wherein they start with that company's steam plant in service from the FERC Form 1. These testimonies are also available on the PUCO website. The steam plant in service amounts include the Mitchell units. In Case No. 10-2929, the PUCO determined an appropriate cost-based capacity

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AUTHORIZING THE TRANSFER TO THE COMPANY OF AN UNDIVIDED FIFTY PERCENT INTEREST IN THE MITCHELL GENERATING STATION AND ASSOCIATED ASSETS; (2) APPROVAL OF THE ASSUMPTION BY KENTUCKY POWER COMPANY OF CERTAIN LIABILITIES IN CONNECTION WITH THE TRANSFER OF THE MITCHELL GENERATING STATION; (3) DECLARATORY RULINGS; (4) DEFERRAL OF COSTS INCURRED IN CONNECTION WITH THE COMPANY'S EFFORTS TO MEET FEDERAL CLEAN AIR ACT AND RELATED REQUIREMENTS; AND (5) ALL OTHER REQUIRED APPROVALS AND RELIEF	**Case No. 2012-00578**

**KIUC'S RESPONSES TO
COMMISSION STAFF'S
FIRST REQUEST FOR INFORMATION**

charge and allowed the Company to defer the difference between the revenues based on that capacity charge and RPM. In Case No. 11-346, the PUCO established a cost-based "state compensation mechanism" that provided for further recoveries of the same costs, subject to an earnings cap under the Significantly Excessive Earnings Test, and recovery of the capacity charges deferrals and the state compensation mechanism deferrals.

IN THE UNITED STATES DISTRICT COURT
FOR THE SOUTHERN DISTRICT OF OHIO
EASTERN DIVISION

UNITED STATES OF AMERICA Plaintiff, and STATE OF NEW YORK, ET AL., Plaintiff-Intervenors, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Consolidated Cases: Civil Action No. C2-99-1182 Civil Action No. C2-99-1250 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Terence P. Kemp
OHIO CITIZEN ACTION, ET AL., Plaintiffs, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-04-1098 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King
UNITED STATES OF AMERICA Plaintiff, v. AMERICAN ELECTRIC POWER SERVICE CORP., ET AL., Defendants.	Civil Action No. C2-05-360 JUDGE EDMUND A. SARGUS, JR. Magistrate Judge Norah McCann King

OAG EXHIBIT 7

THIRD JOINT MODIFICATION TO CONSENT DECREE WITH ORDER MODIFYING CONSENT DECREE

WHEREAS On December 10, 2007, this Court entered a Consent Decree in the above-captioned matters (Case No. 99-1250, Docket # 363; Case No. 99-1182, Docket # 508).

WHEREAS Paragraph 199 of the Consent Decree provides that the terms of the Consent Decree may be modified only by a subsequent written agreement signed by the Plaintiffs and Defendants. Material modifications shall be effective only upon written approval by the Court.

WHEREAS pursuant to Paragraph 87 of the Consent Decree, as modified by a Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on April 5, 2010 (Case No. 99-1250, Docket # 371), and as modified by a second Joint Modification to Consent Decree With Order Modifying Consent Decree, filed on December 28, 2010 (Case No. 99-1250, Docket # 372), the Defendants are required, *inter alia*, to install and continuously operate a Flue Gas Desulfurization System (FGD) no later than December 31, 2015 on Big Sandy Unit 2, December 31, 2015 on Muskingum River Unit 5, December 31, 2017 on Rockport Unit 1, and December 31, 2019 on Rockport Unit 2.

WHEREAS, on October 31, 2012, the Defendants filed an Application for Judicial Interpretation of Consent Decree in Case No. 99-1182 (Docket # 528) and the related cases.

WHEREAS, the United States, the States and Citizen Plaintiffs filed a Memorandum in Opposition (Case No. 99-1182, Docket # 534), and Citizen Plaintiffs filed a Supplemental Memorandum in Opposition (Case No. 99-1250, Docket # 381) to the Defendants' Application.

WHEREAS all Parties made additional filings and the Application was scheduled for a hearing on December 17, 2012.

WHEREAS, the Parties have engaged in settlement discussions and have reached agreement on a modification to the Consent Decree as set forth herein.

WHEREAS, the Parties have agreed, and this Court by entering this Third Joint Modification finds, that this Third Joint Modification has been negotiated in good faith and at arm's length; that this settlement is fair, reasonable, and in the public interest, and consistent with the goals of the Clean Air Act, 42 U.S.C. §7401, *et seq.*; and that entry of this Third Joint Modification without further litigation is the most appropriate means of resolving this matter.

WHEREAS, the Parties agree and acknowledge that final approval of the United States and entry of this Third Joint Modification is subject to the procedures set forth in 28 CFR § 50.7, which provides for notice of this Third Joint Modification in the Federal Register, an opportunity for public comment, and the right of the United States to withdraw or withhold consent if the comments disclose facts or considerations which indicate that the Third Joint Modification is inappropriate, improper, or inadequate. No Party will oppose entry of this Third Joint Modification by this Court or challenge any provision of this Third Joint Modification unless the United States has notified the Parties, in writing, that the United States no longer supports entry of the Third Joint Modification.

NOW THEREFORE, for good cause shown, without admission of any issue of fact or law raised in the Application or the underlying litigation, the Parties hereby seek to modify the Consent Decree in this matter, and upon the filing of a Motion to Enter by the United States, move that the Court sign and enter the following Order:

1. Add a definition of "Cease Burning Coal" as new Paragraph 8A of the Consent Decree as follows:

<u>8A. "Cease Burning Coal" means that Defendants shall permanently cease burning coal for purposes of generating electricity from a Unit, and shall submit all necessary notifications or</u>

requests for permit amendments to reflect the permanent cessation of coal firing at the Unit.

2. Modify the definition of "Continuously Operate" in Paragraph 14 of the Consent Decree as follows:

14. "Continuously Operate" or "Continuous Operation" means that when an SCR, FGD, DSI, ESP, or Other NOx Pollution Controls are used at a Unit, except during a Malfunction, they shall be operated at all times such Unit is in operation, consistent with the technological limitations, manufacturer's specifications, and good engineering and maintenance practices for such equipment and the Unit so as to minimize emissions to the greatest extent practicable.

3. Add a new definition of "Dry Sorbent Injection" or "DSI" as new Paragraph18A of the Consent Decree as follows:

18A. "Dry Sorbent Injection" or "DSI" means a pollution control system in which a sorbent is injected into the flue gas path prior to the particulate pollution control device for the purpose of reducing SO_2 emissions. For purposes of the DSI systems required to be installed at the Rockport Units only, the DSI systems shall utilize a sodium based sorbent and be designed to inject at least 10 tons per hour of a sodium based sorbent. Defendants may utilize a different sorbent at the Rockport Units provided they obtain prior approval from Plaintiffs pursuant to Paragraph 148 of the Consent Decree.

4. Modify the definition of "Improved Unit" in Paragraph 28 of the Consent Decree as follows:

28. An "Improved Unit" for SO_2 means an AEP Eastern System Unit equipped with an FGD or scheduled under this Consent Decree to be equipped with an FGD, or required to be Retired, Retrofitted, Re-Powered, or Refueled.

The remainder of Paragraph 28 shall remain the same.

5. Add a definition of "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" as new Paragraph 48A of the Consent Decree, as follows:

48A. "Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport" means the sum of the tons of SO_2 emitted during all periods of operation from the Rockport Plant, including, without limitation, all SO_2 emitted during periods of startup, shutdown, and Malfunction, during the relevant calendar year (*i.e.*, January 1 – December 31).

6. Add a definition of "Refuel" as new Paragraph 53A of the Consent Decree, as follows:

53A. "Refuel" means, solely for purposes of this Consent Decree, the modification of a unit as necessary such that the modified unit generates electricity solely through the combustion of natural gas rather than coal, including the installation and Continuous Operation of the NO_x controls required by Section IV of this Consent Decree. Nothing herein shall prevent the reuse of any equipment at any existing unit or new emissions unit, provided that AEP applies for, and obtains, all required permits, including, if applicable, a PSD or Nonattainment NSR permit.

7. Modify the definition of "Retrofit" in Paragraph 56 of the Consent Decree as follows:

56. "Retrofit" means that the Unit must install and Continuously Operate both an SCR and an FGD, as defined in the Consent Decree. For purposes of the requirements in Paragraph 87 for the Rockport Units, "Retrofit" also means that the Unit will be equipped with a post-combustion wet- or dry-FGD system with a control technology vendor guaranteed design removal efficiency of 98% or more, and subject upon installation to a 30-Day Rolling Average Emissions Rate of 0.100 lb/mmBTU for SO_2, if the Unit burns coal with an uncontrolled SO_2 emissions rate of 3.0 lb/mmBTU or higher, or a 30-day Rolling Average Emission Rate of 0.060 lb/mmBTU if the

Unit burns coal with an uncontrolled SO_2 emissions rate below 3.0 lb/mmBTU. For the 600 MW listed in the table in Paragraph 68 and 87, "Retrofit" means that the Unit must meet a federally-enforceable 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for NOx and a 30-Day Rolling Average Emission Rate of 0.100 lb/mmBTU for SO2, measured in accordance with the requirements of this Consent Decree.

8. Modify the Eastern System-Wide Annual Tonnage Limitations for SO_2 in the table in Paragraph 86 of the Consent Decree as follows:

86. Notwithstanding any other provision of this Consent Decree, except Section XIV (Force Majeure), during each calendar year specified in the table below, all Units in the AEP Eastern System, collectively, shall not emit SO_2 in excess of the following Eastern System-Wide Annual Tonnage Limitations:

Calendar Year(s)	**Eastern System-Wide Annual Tonnage Limitations for SO_2**	**Modified Eastern System-Wide Annual Tonnage Limitations for SO_2**
2016	~~260,000 tons~~	145,000 tons
2017	~~235,000 tons~~	145,000 tons
2018	~~184,000 tons~~	145,000 tons
2019~~, and each year thereafter~~ - 2021	~~174,000 tons~~	113,000 tons per year
2022 - 2025	~~174,000 tons~~	110,000 tons per year
2026 - 2028	~~174,000 tons~~	102,000 tons per year
2029, and each year thereafter	~~174,000 tons~~	94,000 tons per year

The remainder of the table in Paragraph 86 shall remain the same.

9. Modify the SO_2 pollution control requirements and compliance dates listed in the

table in Paragraph 87 of the Consent Decree for Big Sandy Unit 2, Muskingum River Unit 5, Rockport Units 1 and 2, and Tanners Creek Unit 4 as follows:

87. No later than the dates set forth in the table below, Defendants shall install and Continuously Operate an FGD on each Unit identified therein, or, if indicated in the table, Retire, Retrofit, ~~or~~ Re-power, or Refuel such Unit:

Unit	SO_2 Pollution Control	Modified SO_2 Pollution Control	Date	Modified Date
Big Sandy Unit 2	~~FGD~~	Retrofit, Retire, Re-power, or Refuel	December 31, 2015	NA
Muskingum River Unit 5	~~FGD~~	Cease Burning Coal and Retire Or Cease Burning Coal and Refuel	~~December 31, 2015~~	December 15, 2015 December 31, 2015, unless the Refueling project is not completed in which case the unit will be taken out of service no later than December 31, 2015 and will not restart until the Refueling project is completed. The Refueling project must be completed by June 30, 2017.
First Rockport Unit	~~FGD~~	Dry Sorbent Injection, and Retrofit, Retire, Re-power, or Refuel	~~December 31, 2017~~	April 16, 2015 December 31, 2025.
Second Rockport Unit	~~FGD~~	Dry Sorbent Injection, and	~~December 31, 2019~~	April 16, 2015 and

Unit	**SO_2 Pollution Control**	**Modified SO_2 Pollution Control**	**Date**	**Modified Date**
		Retrofit, Retire, Re-power, or Refuel		December 31, 2028.
Tanners Creek Unit 4	NA	Retire or Refuel	NA	June 1, 2015

The remainder of the table in Paragraph 87 of the Consent Decree shall remain the same, including the Joint Modifications previously made to the compliance deadlines for Amos Units 1 and 2.

10. Add a new Paragraph 89A establishing the Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport, as follows:

89A. For each of the calendar years set forth in the table below, Defendants shall limit their total annual SO_2 emissions from Rockport Units 1 and 2 to Plant-Wide Annual Tonnage Limitations for SO_2 as follows:

Calendar Years	**Plant-Wide Annual Tonnage Limitations for SO_2**
2016 - 2017	28,000 tons per year
2018 - 2019	26,000 tons per year
2020 - 2025	22,000 tons per year
2026 - 2028	18,000 tons per year
2029, and each year thereafter	10,000 tons per year

11. Modify Paragraph 92 of the Consent Decree as follows:

92. Except as may be necessary to comply with this Section and Section XIII (Stipulated Penalties), Defendants may not use any SO_2 Allowances to comply with any requirements of this

Consent Decree, including by claiming compliance with any emission limitation, Eastern System-Wide Annual Tonnage Limitation, Plant-Wide Annual Rolling Average Tonnage Limitation for SO_2 at Clinch River, Plant-Wide Annual Tonnage Limitation for SO_2 at Kammer, or Plant-Wide Annual Tonnage Limitations for SO_2 at Rockport required by this Consent Decree by using, tendering, or otherwise applying SO_2 Allowances to achieve compliance or offset any emission above the limits specified in this Consent Decree.

12. Modify Paragraph 100 of the Consent Decree as follows:

100. To the extent an Emission Rate, 30-Day Rolling Average Removal Efficiency, Eastern System-Wide Annual Tonnage Limitation, or Plant-Wide Annual Tonnage Limitation for SO_2 is required under this Consent Decree, Defendants shall use CEMS in accordance with the reference methods specified in 40 C.F.R. Part 75 to determine the Emission Rate or annual emissions.

13. Modify Paragraph 104 of the Consent Decree as follows:

104. On or before the date established by this Consent Decree for Defendants to achieve and maintain 0.030 lb/mmBTU at Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5, Defendants shall conduct a performance test for PM that demonstrates compliance with the PM Emission Rate required by this Consent Decree. Within forty-five (45) days of each such performance test, Defendants shall submit the results of the performance test to Plaintiffs pursuant to Section XVIII (Notices) of this Consent Decree. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the performance testing requirements for Muskingum River Unit 5 contained in this Paragraph.

14. Modify Paragraph 105 of the Consent Decree as follows:

105. Beginning in calendar year 2010 for Cardinal Unit 1 and Cardinal Unit 2, and calendar year 2013 for Muskingum River Unit 5, and continuing in each calendar year thereafter, Defendants shall conduct a stack test for PM on each stack servicing Cardinal Unit 1, Cardinal Unit 2, and Muskingum River Unit 5. The annual stack test requirement imposed by this Paragraph may be satisfied by stack tests conducted by Defendants as required by their permits from the State of Ohio for any year that such stack tests are required under the permits. On and after the date that Muskingum River Unit 5 complies with the requirement to Cease Burning Coal pursuant to Paragraph 87 of this Consent Decree, Defendants shall no longer be obligated to comply with the stack testing requirements for Muskingum River Unit 5 contained in this Paragraph.

15. Modify Paragraph 119 of the Consent Decree as follows:

119. Defendants shall implement the Environmental Mitigation Projects described in Appendix A to this Consent Decree, shall fund the categories of Projects described in Subsection B, below, and shall implement the Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects described in Subsection C, below, (collectively, the "Projects") in compliance with the approved plans and schedules for such Projects and other terms of this Consent Decree.

The remainder of Paragraph 119 shall remain the same.

16. Add a new Subsection C after Paragraph 128 of the Consent Decree as follows:

C. Citizen Plaintiffs' Renewable Energy Project and Citizen Plaintiffs' Mitigation Projects.

128A. Citizen Plaintiffs' Renewable Energy Project. Defendants shall implement a renewable energy project as described below during the period from 2013 through 2019.

a. If, during the period from 2013-2015, a renewable energy production tax credit of at least 2.2 cents/kwh for ten years is available for new wind electricity production facilities upon which construction is commenced within one year or more after enactment of the tax credit (or an alternative tax benefit is available that provides sufficient economic value so that the levelized cost to customers does not exceed the weighted average cost of any existing contracts with Indiana Michigan Power Company ("I&M") for 50 MW or greater of wind capacity, adjusted for inflation) I&M will secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment. For the avoidance of doubt, so long as the energy production tax credit contained in the American Taxpayer Relief Act of 2012 allows projects that have commenced construction by December 31, 2013, and that are placed in service by December 31, 2014, to qualify for the energy production tax credit provided in that Act, then I&M shall be obligated to secure new renewable energy purchase agreements for 200 MW of new wind energy capacity.

b. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during 2013-2015, but becomes available during 2016-2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M will use commercially reasonable efforts to secure 200 MW of new wind energy capacity from facilities located in Indiana or Michigan that qualify for the production tax credit or alternative tax benefit within two years after enactment.

c. If a renewable energy production tax credit or alternative tax benefit as described in subparagraph a., above, is not available during the period from 2013 – 2019 for new wind electricity production facilities on which construction is commenced within one year or more after the production tax credit or alternative tax benefit is enacted, I&M shall be relieved of its obligations to secure new wind energy capacity under this Paragraph 119A.

128B. Citizen Plaintiffs' Mitigation Projects. I&M will provide $2.5 million in mitigation funding as directed by the Citizen Plaintiffs for projects in Indiana that include diesel retrofits, health and safety home repairs, solar water heaters, outdoor wood boilers, land acquisition projects, and small renewable energy projects (less than 0.5 MW) located on customer premises that are eligible for net metering or similar interconnection arrangements on or before December 31, 2014. I&M shall make payments to fund such Projects within seventy-five (75) days after being notified by the Citizen Plaintiffs in writing of the nature of the Project, the amount of funding requested, the identity and mailing address of the recipient of the funds, payment instructions, including taxpayer identification numbers and routing instructions for electronic payments, and any other information necessary to process the requested payments. Defendants shall not have approval rights for the Projects or the amount of funding requested, but in no event shall the cumulative amount of funding provided pursuant to this Paragraph 128B exceed $2.5 million.

17. Modify Paragraph 127 of the Consent Decree as follows:

127. The States, by and through their respective Attorneys General, shall jointly submit to Defendants Projects within the categories identified in this Subsection B for funding in amounts not to exceed $4.8 million per calendar year for no less than five (5) years following the Date of Entry of this Consent Decree beginning as early as calendar year 2008, and for an additional

amount not to exceed $6.0 million in 2013. The funds for these Projects will be apportioned by and among the States, and Defendants shall not have approval rights for the Projects or the apportionment. Defendants shall pay proceeds as designated by the States in accordance with the Projects submitted for funding each year within seventy-five (75) days after being notified by the States in writing. Notwithstanding the maximum annual funding limitations above, if the total costs of the projects submitted in any one or more years is less than the maximum annual amount, the difference between the amount requested and the maximum annual amount for that year will be available for funding by the Defendants of new and previously submitted projects in the following years, except that all amounts not requested by and paid to the States within eleven (11) years after the Date of Entry of this Consent Decree shall expire.

18. Modify Paragraph 133 of the Consent Decree as follows:

133. Claims Based on Modifications after the Date of Lodging of This Consent Decree. Entry of this Consent Decree shall resolve all civil claims of the United States against Defendants that arise based on a modification commenced before December 31, 2018, or, solely for the first Rockport Unit, before December 31, 2025, or, solely for the second Rockport Unit, before December 31, 2028, for all pollutants, except Particulate Matter, regulated under Parts C or D of Subchapter I of the Clean Air Act, and under regulations promulgated thereunder, as of the Date of Lodging of this Consent Decree, and:

a. where such modification is commenced at any AEP Eastern System Unit after the Date of Lodging of this Consent Decree; or

b. where such modification is one this Consent Decree expressly directs Defendants to undertake.

The remainder of Paragraph 133 shall remain the same.

19. Modify the table in Paragraph 150 of the Consent Decree as follows:

Consent Decree Violation	**Stipulated Penalty (Per Day, Per Violation, Unless Otherwise Specified)**
x. Failure to comply with the Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport	$40,000 per ton, plus the surrender, pursuant to the procedures set forth in Paragraphs 95 and 96, of SO_2 Allowances in an amount equal to two times the number of tons by which the limitation was exceeded
y. Failure to fund a Citizen Plaintiffs' Mitigation Project as required by Paragraph 119B of this Consent Decree	$1,000 per day per violation during the first 30 days, $5,000 per day per violation thereafter
z. Failure to implement the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 128A of this Consent Decree	$10,000 per day per violation during the first 30 days, $32,500 per day per violation thereafter

The remainder of the table in Paragraph 150 shall remain the same.

20. In addition to the requirements reflected in Appendix B (Reporting Requirements) to the Consent Decree, Defendants shall include in their Annual Report to Plaintiffs the following information:

O. Plant-Wide Annual Tonnage Limitation for SO_2 at Rockport

Beginning on March 31, 2017, and continuing annually thereafter, Defendants shall report: (a) the actual tons of SO_2 emitted from Units 1 and 2 at the Rockport Plant for the prior calendar year; (b) the Plant-Wide Annual Tonnage Limitation for SO_2 at the Rockport Plant for the prior calendar year as set forth in Paragraph 89A of the Consent Decree; and (c) for the annual reports for calendar years 2015 – 2028, Defendants shall report the daily average SO_2 emissions from the Rockport Plant expressed in lb/mmBTU, and the daily sorbent deliveries to the Rockport Plant by weight.

P. Citizen Plaintiffs' Renewable Energy Project

Beginning on March 31, 2014, and continuing each year thereafter until completion of the Citizen Plaintiffs' Renewable Energy Project, Defendants shall include a written report detailing the progress of the implementation of the Citizen Plaintiffs' Renewable Energy Project required by Paragraph 119A of the Consent Decree.

Q. Citizen Plaintiffs' Mitigation Projects

Beginning on March 31, 2013, and continuing each year until March 31, 2015, Defendants shall include a written report detailing the progress of implementation of the Citizen

Plaintiffs' Mitigation Projects required by Paragraph 119B of the Consent Decree.

R. By March 31, 2015, Defendants shall notify Plaintiffs of their intent to Retire or Refuel Muskingum River 5.

S. By March 31, 2024, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-Power or Refuel the first Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

T. By March 31, 2027, Defendants shall notify Plaintiffs of their decision to Retrofit, Retire, Re-power or Refuel the second Rockport Unit. If Defendants elect to Retrofit the Unit, Defendants shall provide with such notification, information regarding the removal efficiency guarantee requested from and obtained from the control technology vendor and the sulfur content of the fuel used to design the FGD, including any non-confidential information regarding the SO_2 control technology filed by Defendants with the public utility regulator.

U. If Defendants elect to Retrofit one or both of the Rockport Units, beginning in the annual reports submitted for calendar years 2026 and/or 2029, as applicable, Defendants shall report a 30-Day Rolling Average SO_2 Emission Rate for the Unit(s) that is (are) Retrofit in accordance with Paragraph 5 of the Consent Decree. In addition, Defendants shall report a 30-Day Rolling Average Uncontrolled Emission Rate for SO_2 for the Unit(s) that is(are) Retrofit based on daily as burned coal sampling and analysis or an inlet SO_2 CEMs upstream of the FGD.

The remainder of Appendix B shall remain the same.

21. Except as specifically provided in this Order, all other terms and conditions of the Consent Decree remain unchanged and in full effect.

SO ORDERED, THIS _____ DAY OF ________________, 2013.

____

HONORABLE EDMUND A. SARGUS, JR.
UNITED STATES DISTRICT COURT JUDGE

Respectfully submitted,

FOR THE UNITED STATES OF AMERICA:

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Myles E. Flint by BAW w/ permission

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Faith E Bugel

FAITH BUGEL
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[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

LOCAL COUNSEL FOR SIERRA CLUB, NATURAL RESOURCES DEFENSE COUNCIL, INC., OHIO CITIZEN ACTION, CITIZENS ACTION COALITION OF INDIANA, HOOSIER ENVIRONMENTAL COUNCIL, OHIO VALLEY ENVIRONMENTAL COALITION, WEST VIRGINIA ENVIRONMENTAL COUNCIL, CLEAN AIR COUNCIL, IZAAK WALTON LEAGUE OF AMERICA, ENVIRONMENT AMERICA[1], NATIONAL WILDLIFE FEDERATION, INDIANA WILDLIFE FEDERATION AND LEAGUE OF OHIO SPORTSMEN:

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[1] Environment America is the same entity that signed on to the original Consent Decree as United States Public Interest Research Group.

FOR DEFENDANTS AMERICAN ELECTRIC POWER SERVICE CORPORATION, ET AL.:

David Feinberg

DAVID M. FEINBERG
General Counsel
American Electric Power Service Corporation
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Kentucky Power Company
Rate Change Comparison
($000)

Line No.	Description	DFGD Filing (1)	Jan 2014 - Jun 2015 Mitchell Transfer Overlap Period (2)	July 2015 forward Mitchell Transfer Post BSU2 Retirement (3)
1	COS Impact	$ 177,699 A.	$ 44,000 F.	$ 81,244 J.
	Adjustments:			
2	Big Sandy Fuel Savings	$ (18,211) B.	N/A	N/A
3	Mitchell Fuel Savings	N/A	$ (16,750) G.	$ (16,750)
4	Pool Elimination (4)	$ (21,304) C.	$ -	$ (21,304)
5	Environmental Pool Adjustment	$ (7,320) D.	$ - H.	$ (7,320)
6	SS Tariff Adjustment	N/A	$ - I.	N/A
7	BSU2 Decommissioning Costs	N/A	N/A	$ 7,948 K.
8	BSU2 Amort. Of Undepr. Balance	N/A	N/A	$ 21,056 L.
9	BSU2 Study Costs	N/A	N/A	$ 6,598 M.
10	Total of Adjustments	$ (46,835)	$ (16,750)	$ (9,772)
11	Adjusted COS Impact	$ 130,864	$ 27,250	$ 71,472
12	Case 2013-00197 Juris. Revenues	$ 511,321 E.	$ 511,321	$ 511,321 N.
13	Percent Change	25.59%	5.33%	13.98% N.
14	Incremental 2015 Percent Change			8.21% O.

Columns (2) and (3) are not additive.

A. Exhibit LPM-2, Case No. 2011-00141
B. Staff's Fourth Set of Data Requests in Case No. 2012-00578, Item No. 9, Attachment 1, Page 3 of 3.
Average of two calendar 2013 values.
C. Section V, Workpaper S-4, Page 4, Case No. 2013-00197
D. Section V, Workpaper S-4, Page 62, Case No. 2013-00197
E. Section V, Schedule 5 - Jurisdictional Operating Revenues, Case No. 2013-00197
F. Memorandum of Understanding filed in Case No. 2012-00578, Paragraph 4
G. Memorandum of Understanding filed in Case No. 2012-00578, Paragraph 2
H. Memorandum of Understanding filed in Case No. 2012-00578, Paragraph 5
I. Memorandum of Understanding filed in Case No. 2012-00578, Paragraph 7
J. Includes removal of BSU2 O&M and Depreciation - see Attachment Page 2
K. $85.227 M collected over 25 years with carrying costs at WACC (8.08%)
L. $225.795 M collected over 25 years with carrying costs at WACC (8.08%)
M. $28,113,304 collected over 5 years with interest at long-term debt rate of 6.48%
N. Revenues would be higher and % increase lower if MOU implemented 1/1/2014
O. Does not reflect changes in other (Non-Mitchell) costs or revenues, if any,
that may be part of future rate case.

OAG EXHIBIT 8

Mitchell Transfer net of BSU2 O&M and Depreciation

Adjustment from Section V Case No. 2013-00197	Operating Income Adjustments Increase/(Decrease)	Rate Base Adjustments Increase/(Decrease)
Workpaper S-4, Page 68		($2,121,105)
Workpaper S-4, Page 66	($26,692,002)	($2,452,091)
Workpaper S-4, Page 65	$170,885	
Workpaper S-4, Page 61	$2,555,341	($3,533,283)
Workpaper S-4, Page 60	$6,083,567	$1,236,629
Workpaper S-4, Page 59	$46,951,763	$537,878,563
Workpaper S-4, Page 58	($2,832,147)	
Workpaper S-4, Page 57	($124,099)	($25,226)
Workpaper S-4, Page 56	($166,288)	($33,802)
Workpaper S-4, Page 50-55	$26,227	$3,797
Workpaper S-4, Page 49		($1,151,258)
Workpaper S-4, Page 48	($301,638)	($61,315)
Workpaper S-4, Page 47	($462,238)	($93,961)
Estimated Big Sandy Net Book Value		($225,795,000)
Total	$ 25,209,371	$ 303,851,948
Return on Rate Base @ 8.08%		$ 24,551,237
Total Income Requirement		$ 49,760,608
Total Revenue Requirement (GRCF @ 1.6327)		**$ 81,244,145**

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

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

REBUTTAL TESTIMONY

OF

JOHN M. MCMANUS

April 16, 2012

OAG EXHIBIT 9

REBUTTAL TESTIMONY OF
JOHN M. MCMANUS, ON BEHALF OF
KENTUCKY POWER COMPANY
BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

CASE NO. 2011-00401

TABLE OF CONTENTS

REBUTTAL TESTIMONY OF JOHN M. MCMANUS, ON BEHALF OF KENTUCKY POWER COMPANY BEFORE THE PUBLIC SERVICE COMMISSION OF KENTUCKY

I. INTRODUCTION

Q: PLEASE STATE YOUR NAME, POSITION, AND BUSINESS ADDRESS.

A: My name is John M. McManus. I am employed by American Electric Power Service Corporation as Vice President - Environmental Services. American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), the parent of Kentucky Power Company (KPCo or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q: ARE YOU THE SAME JOHN MCMANUS THAT FILED DIRECT TESTIMONY IN THIS PROCEEDING ON THE BEHALF OF KPCO?

A: Yes, I am.

II. PURPOSE OF TESTIMONY

Q: WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A: The purpose of my testimony is to explain why Kentucky Industrial Utility Customers (KIUC) witness Lane Kollen's recommendation to idle Big Sandy Unit 2 and restart the Big Sandy Unit 2 environmental retrofit process at a later date, as stated on page 18 - lines 1-4 of his Direct Testimony, is impractical. The recommendation overlooks certain current compliance obligations and future environmental permitting-related impacts that could occur as a result of idling a plant for an extended period of time.

Q. ARE YOU SPONSORING ANY EXHIBITS?

A. No, I am not.

III. AIR PERMITTING

Q: KIUC WITNESS KOLLEN SUGGESTS ON PAGE 18, LINES 1-2 OF HIS DIRECT TESTIMONY, THAT THE COMPANY "RESTART THE RETROFIT PROCESS AT A LATER DATE IF AND WHEN THE COMMISSION SUBSEQUENTLY FINDS THAT THE RETROFIT IS ECONOMIC." WHAT ARE THE IMPLICATIONS OF WITNESS KOLLEN'S RECOMMENDATION?

A. Under the current project schedule, Big Sandy Unit 2 will be taken out of service at the beginning of 2016 to tie-in the completed FGD system and will return to service about mid-year with the FGD system operational. This schedule assumes that the unit will be granted a one year extension of the MATS compliance deadline while the retrofit project is being completed. Delaying the FGD retrofit project an extended period of time will likely result in Big Sandy 2 having to be taken out of service by April 16, 2015, the initial MATS deadline, as an extension of the deadline would not be granted if the Company is not fully engaged in a retrofit project, and the unit cannot meet the MATS emissions limits with its current emissions controls. Placing the retrofit process on hold now and restarting at some point in the future will require 4 ½ - 5 years before Big Sandy Unit 2 could be placed in-service with the new controls, resulting in an extended period during which the unit would be idled.

Idling the unit for such an extended period could introduce significant risk and additional capital costs to comply with potential increased scope and stringency of future air emission requirements. EPA has a well-established policy that allows facilities to select a baseline level of emissions from the highest consecutive 24-month period during the previous five years to determine whether changes at the facility are subject to the Prevention of Significant Deterioration ("PSD") / New Source Review ("NSR") air permitting requirements. 40 CFR §51.165(a)(1)(xxxv)(*A*). In addition, the current general provisions of the New Source Performance Standards (NSPS) exclude existing facilities from the new source standards if the changes made at an existing facility do not increase the hourly emission rates for any regulated pollutant above the rate achievable at the facility within five years prior to the change. 40 CFR §60.14(h). Electing to idle a facility for an extended period of time imposes a serious risk that could result in a requirement to obtain a PSD/NSR air permit and meet Best Available Control Technology (BACT) requirements, and/or trigger the application of NSPS at Big Sandy 2 in order to commence construction of any emission control technologies and eventually return the unit to service.

Q. PLEASE EXPLAIN WHAT ADDITIONAL RISKS OR COSTS MIGHT BE INCURRED IF BIG SANDY IS CONSIDERED A NEW SOURCE FOR PURPOSES OF THE PSD/NSR OR NSPS PROGRAMS.

A. In general, standards for "new" sources are more stringent than those that apply to existing sources. In addition, PSD/NSR air permitting for a new or modified source is much more complex and time-consuming than permitting an emission control project for an existing source in operation, which can often be accomplished with a minor source permit. For example, treatment as a new source would subject all emission sources at the facility, including the main boiler, auxiliary boiler, emergency generators, and material handling sources, to a Best Available Control Technology ("BACT") analysis. This could result in more stringent emission limits and the requirement to install additional emission controls on such sources. Conversely, the air permitting process for an existing unit undertaking an emission control project would be focused only on new emission sources or changes to the emissions profile of existing emissions units resulting from that project. In addition, idling Big Sandy 2 for any extended period of time could subject the unit to the NSPS, including the recently proposed NSPS for carbon dioxide or any future CO_2 NSPS for modified sources.

Q. DESCRIBE THE GREENHOUSE GAS NEW SOURCE PERFORMANCE STANDARD RECENTLY PROPOSED BY THE U.S. ENVIRONMENTAL PROTECTION AGENCY (EPA).

A. The EPA announced a proposal for a NSPS for GHGs from new power plants on March 27, 2012. The proposed rulemaking only concerns new fossil fuel-fired electric generating units (EGUs) that will be built in the future, and does not apply to existing units already operating or units that will start construction over the next 12 months. For purposes of this rule, fossil fuel-fired EGUs include fossil fuel-fired boilers, integrated gasification combined cycle (IGCC) units and stationary combined cycle turbine units that generate electricity for sale and are larger than 25 megawatts (MW). The proposal would not apply to existing units, including modifications such as changes needed to meet other air pollution standards. The proposed standard would require that new fossil fuel-fired power plants meet an output-based standard of 1,000 lbs. of CO_2 per megawatt-hour (lb. CO_2/MWh Gross).

Q. IF THE BIG SANDY UNIT 2 FGD PROJECT IS SUSPENDED AND RESTARTED AT A LATER DATE, HOW COULD THE EPA'S PROPOSED CO_2 STANDARD FOR NEW POWER PLANTS IMPACT THE UNIT?

A. If EPA finalizes the new source CO_2 NSPS as proposed, or develops a CO_2 NSPS for modified sources, and Big Sandy 2 became subject to one or the other as a result of an extended period without operation, the unit would have to meet the applicable limit before returning to operation. This could require the unit to be equipped with technology to capture and sequester CO_2 emissions, with the associated cost of that technology (assuming it is even available), or it would have to be permanently shutdown.

Q. ARE THERE ANY ADDITIONAL RISKS ASSOCIATED WITH IDLING BIG SANDY 2 FOR AN EXTENDED PERIOD?

A. Yes. Over the past several years the Environmental Protection Agency has revised and reduced the level of various National Ambient Air Quality Standards (NAAQS) repeatedly. Each new round of revisions creates additional compliance planning obligations for the state agencies, and has resulted in more stringent air emission requirements, particularly for new sources. There is a risk that Big Sandy could be located in a nonattainment area for one or more pollutants at the time it would be reactivated, resulting in requirements to achieve the "Lowest Achievable Emission Rate" (LAER) for any nonattainment pollutant, and to obtain offsets from other sources in order to resume operations. LAER emission rates are the most stringent under the Clean Air Act, and offsets can be difficult to obtain.

Q. **WHAT OTHER ISSUES WOULD ARISE FROM KIUC WITNESS KOLLEN'S RECOMMENDATION?**

A. The Company is required by its 2007 New Source Review (NSR) Consent Decree to equip Big Sandy Unit 2 with a flue gas desulfurization (FGD) system by December 31, 2015. Witness Kollen's recommendation to restart the retrofit process at a date that would occur after the NSR compliance deadline would require the consent of all of the signatories in order to modify the consent decree. While AEP has successfully negotiated modest changes to FGD retrofit schedules for two of the Amos Units, AEP has not requested any change as significant as the one proposed by witness Kollen, and has no ability to compel the other parties to agree to such a significant change.

IV. CONCLUSION

Q. **PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.**

A. A strategy of idling the unit for an extended period and then restarting the retrofit project is not a viable option as such an approach could subject the unit to a more complex and time-consuming air permitting process, could result in more stringent air emission limits, and may require more extensive emission control systems to be installed. In addition, the Company would not be in compliance with the existing requirements of the 2007 NSR Consent Decree for Big Sandy Unit 2, and successful renegotiation of the existing compliance obligations cannot be assumed.

Q. **DOES THIS CONCLUDE YOUR PRE-FILED REBUTTAL TESTIMONY?**

A. Yes.

VERIFICATION

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

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 12 day of April 2012.

Notary Public

My Commission Expires: 12/31/2014

NOTARIAL SEAL
STATE OF OHIO

PATRICK R OTT
NOTARY PUBLIC - OHIO
MY COMMISSION EXPIRES
DECEMBER 31, 2014

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

JOINT APPLICATION OF LOUISVILLE GAS AND ELECTRIC COMPANY AND KENTUCKY UTILITIES COMPANY FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY AND SITE COMPATIBILITY CERTIFICATE FOR THE CONSTRUCTION OF A COMBINED CYCLE COMBUSTION TURBINE AT THE CANE RUN GENERATING STATION AND THE PURCHASE OF EXISTING SIMPLE CYCLE COMBUSTION TURBINE FACILITIES FROM BLUEGRASS GENERATION COMPANY, LLC IN LAGRANGE, KENTUCKY	CASE NO. 2011-00375

O R D E R

On September 15, 2011, Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively "Joint Applicants") filed an application pursuant to KRS 278.020, 807 KAR 5:001, Sections 8 and 9, and KRS 278.216, requesting a Certificate of Public Convenience and Necessity ("CPCN") and a Site Compatibility Certificate for the construction of a 640 MW natural gas combined cycle combustion turbine ("CR 7") at the Joint Applicants' Cane Run Generating Station ("Cane Run") in Louisville, Kentucky, and for the purchase of natural gas simple cycle generation facilities in LaGrange, Kentucky from Bluegrass Generation Company, LLC ("Bluegrass Generation") which include three turbines with a combined capacity of 495 MW. The estimated cost of constructing the facilities at Cane Run, including a 20-inch natural gas pipeline, is $583 million. The cost of the Bluegrass Generation purchase is $110 million. Joint Applicants propose an optimal ownership split of CR 7 with KU

OAG EXHIBIT 10

owning 78 percent and LG&E owning 22 percent.[1] For the Bluegrass Generation facilities, the Joint Applicants propose an ownership arrangement of 31 percent for KU and 69 percent for LG&E.[2] The ownership split balances the production cost savings of CR 7 and balances each company's individual reserve margins through 2020. The proposed natural gas generating facilities are intended to replace the energy and capacity currently provided by the Joint Applicants' Cane Run, Tyrone, and Green River coal-fired units, which are slated to be retired in 2016.

The following parties were granted full intervention in this matter: (1) the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention; (2) Kentucky Industrial Utility Customers, Inc. ("KIUC"); and (3) Sierra Club and Natural Resources Defense Council (collectively "Environmental Intervenors"). On October 18, 2011, the Commission issued an Order establishing a procedural schedule for the processing of this matter. The procedural schedule provided for two rounds of discovery on the Joint Applicants, an opportunity for the filing of intervenor testimony, one round of discovery on intervenor testimony, and an opportunity for the Joint Applicants to file rebuttal testimony.

The Commission scheduled and held a public meeting in Louisville, Kentucky on March 8, 2012 to receive public comments on the Joint Applicants' proposal to construct a combined cycle natural gas combustion turbine at Cane Run and the proposed acquisition of the simple cycle gas combustion turbines from Bluegrass Generation. A

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[1] Application, ¶ 11; Direct Testimony of David S. Sinclair ("Sinclair Testimony"), Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 35.

[2] *Id.*

formal hearing was conducted at the Commission's offices in Frankfort, Kentucky on March 20, 2012. The parties submitted post-hearing briefs on April 3, 2012. The matter is now before the Commission for a decision.

JOINT APPLICANTS' PROPOSAL

Joint Applicants maintain that their self-build proposal, as well as the proposed Bluegrass Generation acquisition, represents the least-cost option to comply with certain new and pending environmental regulatory requirements under the Federal Clean Air Act as amended. Joint Applicants state that the decision to retire their coal-fired generating facilities at Cane Run, Green River, and Tyrone was driven by the proposed Cross-State Air Pollution Rule ("CSAPR"), the Mercury and Air Toxics Standards ("MATS")[3] rule, and the National Ambient Air Quality Standards ("NAAQS").

CSAPR, which was finalized by the EPA on July 6, 2011, requires certain states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.[4] CSAPR imposes significant

[3] At the time of the filing of the instant application, the national emission standards for hazardous air pollutants aimed at reducing mercury, other metals, acid gases, and organic air toxics was known as the HAPS rule. On December 21, 2011, the federal Environmental Protection Agency ("EPA") finalized the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-Fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial–Institutional Steam Generating Units. The final HAPS rule became effective on April 16, 2012 and is now known as the MATS rule or the Utility Maximum Achievable Control Technology "Utility MACT" rule.

[4] On December 30, 2011, in civil actions for review brought by several stakeholders, the United States Court of Appeals for the District of Columbia Circuit entered an order staying the implementation of CSAPR pending the court's resolution of the various petitions for review. The EPA is to continue administering the Clean Air Interstate Rule pending the court's resolution of the petitions for review.

reductions in sulfur dioxide ("SO_2") and nitrogen oxide ("NO_x") emissions that cross state lines beginning in 2012, with still more stringent SO_2 reductions in 2014.[5] Joint Applicants note that "CSAPR creates more stringent state-specific allowance budgets (or 'caps') for SO_2 and NO_x, and would allow for only limited interstate allowance trading to ensure that individual states actually have to make the reductions EPA desires . . . ."[6]

The MATS rule for power plants would reduce emissions from new and existing coal- and oil-fired electric utility steam generating units larger than 25 MW that produce electricity for consumption by the public. Any units which began construction after May 3, 2011 will be considered a new source and must be in compliance within 60 days after the rule is published in the *Federal Register*,[7] or upon startup, whichever is later. Existing units, or those units constructed on or before May 3, 2011, will have three years, plus 60 days after the rule is published in the *Federal Register,* to be in compliance (or April 16, 2015). There is also a possibility that a one-year extension may be granted to install the control devices. In addition, the EPA is providing a pathway for reliability critical units to obtain a schedule with up to an additional year (for a total of 5 years possible) to achieve compliance.[8] MATS would reduce emissions of

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[5] Kentucky is one of 16 states that will be subject to further SO_2 reductions in 2014 under CSAPR.

[6] Direct Testimony of Gary H. Revlett at p. 6.

[7] The MATS rule was published in the *Federal Register* on February 16, 2012, under 77 Fed. Reg. 9,304 (to be codified at 40 C.F.R. pts. 60 and 63).

[8] *See* December 16, 2011 Policy Memorandum issued by the EPA's Office of Enforcement and Compliance Assurance, re The Environmental Protection Agency's Enforcement Response Policy for use of Clean Air Act Section 113(a) Administrative Orders in Relation to Electric Reliability and the Mercury and Air Toxics Standard. Available at: www.epa.gov/compliance/resources/policies/civil/erp/mats-erp.pdf.

heavy metals, including mercury, arsenic, chromium, and nickel; and acid gases, including hydrochloric acid and hydrofluoric acid. These requirements would require the installation of Maximum Achievable Control Technology.

Lastly, Joint Applicants point out that air quality in Jefferson County currently fails to meet SO_2 requirements and the EPA's NAAQS will further restrict NO_x and SO_2 emissions beginning in 2016 and 2017. LG&E performed an evaluation of NAAQS compliance and concluded that retiring the Cane Run facility, constructing CR 7, and installing a scrubber at its Mill Creek Generating Station would reduce SO_2 in Jefferson County by 70 percent. Given these actions, Jefferson County should achieve attainment of SO_2 NAAQS and the Cane Run generation station would be in compliance with NO_x NAAQS.

In Case Nos. 2011-00161[9] and 2011-00162,[10] the Joint Applicants sought and received Commission approval of their 2011 Environmental Compliance Plans, which plans were the result of a comprehensive analysis that determined, on a unit-by-unit basis, whether it would be more cost-effective to install identified pollution control facilities or to retire the unit and buy replacement capacity. Based on the operating characteristics, age, and size of the units, the Joint Applicants determined that the cost of additional emission controls on their six coal-fired units at the Cane Run, Green

[9] Case No. 2011-00161, Application of Kentucky Utilities Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Environmental Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011).

[10] Case No. 2011-00162, Application of Louisville Gas and Electric Company for Certificates of Public Convenience and Necessity and Approval of its 2011 Compliance Plan for Recovery by Environmental Surcharge (Ky. PSC Dec. 15, 2011).

River, and Tyrone generating plants could not be justified and that they should be retired by the end of 2015. The six coal-fired units to be retired have a combined capacity of 797 MWs.

Based on the joint load forecast that was used to prepare the Joint Applicants 2011 Integrated Resource Plan ("IRP"), the retirements of the Cane Run, Green River, and Tyrone coal units would contribute to the Joint Applicants experiencing a capacity shortfall of 877 MWs beginning in 2016 and increasing to 1,066 MWs in 2018.[11] Joint Applicants' projected total annual demand through 2018 reflects the difference between forecasted peak load and peak reductions, which reductions include the impacts of interruptible demands and Demand-Side Management ("DSM") programs.[12] The retirement of the Cane Run and Green River coal units would also impact the Joint Applicants' energy needs.[13] From 2006 through 2010, the combined energy produced by these coal units averaged 4,225 GWh.[14] Joint Applicants' 2011 IRP projects combined energy sales in 2016 to be 36,615 GWh and, in 2017, to be 37,074 GWh.[15] Lastly, the retirements will result in a 2016 reserve margin of approximately 4 percent versus Joint Applicants' target reserve margin of 16 percent.[16]

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[11] Sinclair Testimony, p. 15; Exhibit DSS-1, Joint Applicants 2011 Resource Assessment, p. 11.

[12] *Id.*

[13] *Id.*

[14] *Id.*

[15] *Id.*

[16] *Id.*

To address the projected capacity and energy deficit beginning in 2016, the Joint Applicants issued a request for proposals ("RFP") on December 1, 2010 for capacity and energy to more than 116 potential energy suppliers.[17] The RFP sought responses from parties with resources that would qualify as a Designated Network Resource for transmission purposes.[18] The RFP encouraged offers for firm summer and winter capacity ranging between 1 MW and 700 MW with the Joint Applicants having the flexibility to procure more or less than 700 MW, as well as the authority to aggregate capacity and energy from multiple parties to meet its needs.[19] Joint Applicants received 18 responses containing 50 offers.[20] The responses included power purchase agreements and asset sale offers for gas, coal,[21] nuclear, wind, biomass, and solar technologies.[22]

Joint Applicants' analysis of the RFP responses was conducted in two phases.[23] Phase I consisted of an initial screening of the responses through a scoring system,

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[17] Sinclair Testimony, p. 16; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 13.

[18] *Id.*

[19] *Id.*

[20] *Id.*

[21] Although the Joint Applicants received asset sale offers for coal as part of the responses to their RFP, they did not develop a site specific cost estimate for a new coal unit at Cane Run because the Joint Applicants' 2011 IRP did not identify coal as part of the companies' least-cost resource plan. *See* Sinclair Testimony, p. 17.

[22] Joint Applicants' Post-Hearing Brief, p. 3.

[23] Sinclair Testimony, p. 17; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 4.

which evaluated certain criteria such as cost, term, and site availability.[24] The scoring system was developed as follows: First, responses with unacceptable terms or sites were eliminated; second, the responses were ranked based on two cost measures: (a) levelized revenue requirements per MWh; and (b) levelized revenue requirements per firm capacity-year.[25] The 24 offers that scored the most favorable in both cost categories were selected for Phase II consideration.[26]

The Phase II analysis was conducted in two parts.[27] First, the preliminary Phase II analysis evaluated the top 24 Phase I offers, both individually and in various combinations, in more detail.[28] Joint Applicants utilized the Strategist resource planning software to assess each response's impact on future capacity needs and to determine capital revenue requirements.[29] Joint Applicants also utilized the PROSYM production costing model to evaluate the production cost revenue requirements associated with each offer.[30] A total system revenue requirement for the study period was then calculated using the capital revenue requirements, the production cost revenue requirements, and the revenue requirements for any fixed operation and maintenance

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[24] *Id.*

[25] Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 15.

[26] *Id.*

[27] Sinclair Testimony, p. 17; Exhibit DSS-1, Joint Applicants' 2011 Resource Assessment, p. 16.

[28] *Id.*

[29] Joint Applicants' 2011 Resource Assessment, p. 16.

[30] *Id.*

expenses, gas transportation costs, and firm electric transmission costs.[31] Strategist was then used to develop the least-cost expansion plan for each offer.[32] Production costs were then developed for each expansion plan and each alternative was analyzed based on its impact on the Joint Applicants' ability to serve native load only.[33] The offers were further evaluated under two limited economy market purchase scenarios: (1) no economy purchases; and (2) limited economy purchases.[34] The analysis was conducted relative to a base case scenario for natural gas and electric prices.[35]

The final Phase II analysis consisted of the Joint Applicants meeting with the top respondents and asking them to update their offers to best and final offers.[36] The updated offers were evaluated along with additional self-build options and were analyzed similar to the preliminary Phase II analysis.[37] Based on the RFP and self-build analysis, the Joint Applicants determined that the least-cost alternative for meeting their future capacity and energy needs was to build a new natural gas combined cycle combustion turbine at Cane Run and to purchase from Bluegrass Generation its existing simple cycle combustion turbine facilities in LaGrange, Kentucky.

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[31] *Id.*

[32] Joint Applicants' 2011 Resource Assessment, p. 18.

[33] Joint Applicants' 2011 Resource Assessment, p. 19.

[34] *Id.*

[35] *Id.*

[36] *Id.*

[37] *Id.*

ENVIRONMENTAL INTERVENORS' POSITION

Environmental Intervenors recommend that the Joint Applicants' proposal be denied. Environmental Intervenors argued that the "exclusively natural gas generation" proposed by the Joint Applicants is not the least-cost alternative to address the Joint Applicants' capacity shortfall. Environmental Intervenors maintain that a diversified portfolio that combines additional DSM programs, renewable energy, and natural gas would be a lower-cost option for the Joint Applicants' ratepayers because it would delay or reduce the need for more expensive natural gas capacity additions.[38]

Environmental Intervenors contend that the Joint Applicants failed to identify a least-cost plan that included all cost-effective DSM programs beyond those programs that were approved by the Commission in the Joint Applicants' most recent DSM application, Case No. 2011-00134.[39] Environmental Intervenors point out that the 0.52 percent level of annual energy savings that the Joint Applicants' existing DSM programs are projected to achieve is substantially below the level of energy savings being achieved by DSM programs in other states.[40] Environmental Intervenors further point out that the Joint Applicants' own DSM consultant, ICF International ("ICF"), issued a report that indicated, among other things, that the benefits of the Joint Applicants' DSM

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[38] Environmental Intervenors' Post-Hearing Brief, p. 23.

[39] Case No. 2011-00134, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for Review, Modification, and Continuation of Existing, and Addition of New Demand-Side Management and Energy-Efficiency Programs (Ky. PSC Nov. 9, 2011).

[40] Environmental Intervenors' Post-Hearing Brief, p. 12.

programs outweighed their costs by a ratio of three-to-one or more.[41] According to the Environmental Intervenors, this high benefit-to-cost ratio establishes that the Joint Applicants could achieve more energy savings if they were to expand on their existing DSM programs or implement new DSM programs such as in the commercial and industrial customer classes.[42] Environmental Intervenors note that a more robust DSM portfolio that would achieve annual energy savings of at least one percent would reduce the present value revenue requirement ("PVRR") for the Joint Applicants' energy production, thereby delaying the need for capacity and/or reducing the amount of capacity needed.[43]

Environmental Intervenors also asserted that the Joint Applicants engaged in a perfunctory review of alternative renewable resources.[44] Noting that potential energy suppliers had only a six-week time frame over the Christmas and New Year's holidays to provide complete proposals, Environmental Intervenors argue that the Joint Applicants' "RFP process was abbreviated to the point where it was unlikely to result in a wide array of renewable energy resource proposals."[45] In addition, Environmental Intervenors also claimed that, by assigning a 15 percent capacity factor to wind resources, the Joint Applicants focused only on capacity that wind generation could provide at periods of peak summer energy demand and failed to recognize the

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[41] Environmental Intervenors' Post-Hearing Brief, p. 14.

[42] *Id.*

[43] Environmental Intervenors' Post-Hearing Brief, p. 12.

[44] Environmental Intervenors' Post-Hearing Brief, p. 19.

[45] *Id.*

"significant contribution that wind resources can make to meeting the Companies energy needs."[46] Based on the Joint Applicants' own modeling, Environmental Intervenors maintain that evaluating a one percent DSM energy savings combined with the wind resource proposals received during the RFP would delay the Joint Applicants' need for additional gas generating capacity in 2020 until 2025.[47]

Lastly, Environmental Intervenors argue that the Joint Applicants have arbitrarily assigned a value of $0 to likely future greenhouse gas regulations.[48] Environmental Intervenors contend that the value assumed by the Joint Applicants does not accurately reflect the future costs of CR 7 and that such a value skews the analysis in favor of natural gas and coal-fired generation and against DSM and renewable generation.[49]

KIUC'S POSITION

In its post-hearing brief, KIUC states that it does not oppose the Joint Applicants' decision to retire the six coal-fired units at the Cane Run, Tyrone, and Green River generating stations. KIUC also stated that it did not oppose the Joint Applicants' proposal to construct a natural gas-combined cycle facility at Cane Run and purchase three existing simple cycle gas combustion turbines from Bluegrass Generation in order to meet the capacity deficiency that results from retiring the six coal units. Agreeing with the Joint Applicants, KIUC maintains that the Joint Applicants' proposal is

[46] *Id.*

[47] Environmental Intervenors' Post-Hearing Brief, p. 21.

[48] *Id.*

[49] *Id.*

reasonable and cost-effective in light of the new EPA air emissions regulations impacting coal generating units and the current low price of natural gas.

KIUC disagreed with the Environmental Intervenors' position that the Joint Applicants' capacity deficit could be met through a combination of wind generation purchases and DSM. KIUC noted that the evidence presented by the Joint Applicants established that the wind generation bid in response to the Joint Applicants' RFP was neither cost-effective nor reliable when compared to the Joint Applicants' proposal. Lastly, KIUC contends that the Environmental Intervenors' argument that the Joint Applicants should expand their DSM portfolio to include industrial customers would violate KRS 278.285(3)[50] and that the Joint Applicants' "large industrial load is not the untapped DSM resource that the Environmental Intervenors imagine it to be."[51]

DISCUSSION

No utility may construct any facility to be used in providing utility service to the public until it has obtained a CPCN from this Commission.[52] To obtain a CPCN, the

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[50] KRS 278.285(3) provides, in relevant part, as follows:

> The commission shall allow individual industrial customers with energy intensive processes to implement cost-effective energy efficiency measures in lieu of measures approved as part of the utility's demand-side management programs if the alternative measures by these customers are not subsidized by other customer classes. Such individual industrial customers shall not be assigned the cost of demand-side management programs.

[51] KIUC's Post-Hearing Brief, p. 2.

[52] KRS 278.020(1).

utility must demonstrate a need for such facilities and an absence of wasteful duplication.[53]

"Need" requires:

> [A] showing of a substantial inadequacy of existing service, involving a consumer market sufficiently large to make it economically feasible for the new system or facility to be constructed or operated.
>
> [T]he inadequacy must be due either to a substantial deficiency of service facilities, beyond what could be supplied by normal improvements in the ordinary course of business; or to indifference, poor management or disregard of the rights of consumers, persisting over such a period of time as to establish an inability or unwillingness to render adequate service.[54]

"Wasteful duplication" is defined as "an excess of capacity over need" and "an excessive investment in relation to productivity or efficiency, and an unnecessary multiplicity of physical properties."[55] To demonstrate that a proposed facility does not result in wasteful duplication, we have held that the applicant must demonstrate that a thorough review of all reasonable alternatives has been performed.[56] Selection of a proposal that ultimately costs more than an alternative does not necessarily result in

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[53] *Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 252 S.W.2d 885 (Ky. 1952).

[54] *Id.* at 890.

[55] *Id.*

[56] Case No. 2005-00142, Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for the Construction of Transmission Facilities in Jefferson, Bullitt, Meade, and Hardin Counties, Kentucky (Ky. PSC Sept. 8, 2005).

wasteful duplication.[57] All relevant factors must be balanced.[58] The Commission has long recognized that the principle of least cost is one of the fundamental foundations utilized when setting rates that are fair, just, and reasonable and that this principle is embedded in KRS 278.020(1).[59]

Based on the evidence of record, the Commission finds that the Joint Applicants have established that the proposed facilities are needed to address significant capacity shortfalls beginning in 2016 due to the need to retire the coal-fired generating units at the Cane Run, Green River, and Tyrone Stations, as well as projected load growth. Joint Applicants' decision to retire these coal units was the result of an extensive analysis to determine the least-cost alternative to comply with the aforementioned new and pending air emissions standards. Moreover, the Joint Applicants have sufficiently demonstrated that, absent additional capacity resources, their joint load forecasts and projected energy savings from DSM and energy efficiency projects indicate capacity shortfalls of 877 MW in 2016 and increasing to 1,066 MW in 2018 due to the retirements of the aforementioned coal units and projected load growth.

With respect to the Joint Applicants' proposed Bluegrass Generation acquisition, the parties to this matter have voiced no objection to this proposal. On the contrary,

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[57] *See Kentucky Utilities Co. v. Pub. Serv. Comm'n*, 390 S.W.2d 168, 175 (Ky. 1965). *See also* Case No. 2005-00089, Application of East Kentucky Power Cooperative, Inc. for a Certificate of Public Convenience and Necessity for the Construction of a 138 kV Electric Transmission Line in Rowan County, Kentucky (Ky. PSC Aug. 19, 2005).

[58] Case No. 2005-00089, East Kentucky Power, Order dated August 19, 2005, at 6.

[59] Case No. 2009-00545, Application of Kentucky Power Company for Approval of Renewable Energy Purchase Agreement for Wind Energy Resources Between Kentucky Power Company and FPL Illinois Wind, LLC (Ky. PSC Jun. 28, 2010).

both Environmental Intervenors and KIUC expressly support approval of the purchase of the Bluegrass Generation facility. The Commission agrees and finds that the purchase of the Bluegrass Generation assets is part of the least-cost solution to the Joint Applicants' capacity needs. The evidence establishes that the purchase price of $110 million, or approximately $222/kW, is significantly less expensive than the estimated $850/kW cost to construct a comparable simple cycle gas combustion turbine as set forth in the Joint Applicants' 2011 Integrated Resource Plan. The evidence further establishes that the Bluegrass Generation facilities will assist the Joint Applicants in managing the reliability risks associated with Cane Run, Green River, and Tyrone as these units approach retirement; they will also help the Joint Applicants manage risks while CR 7 is being constructed and placed into operation; and they will allow the Joint Applicants to defer by one year the need for future generating capacity.

With respect to the proposal to construct CR 7, the Commission finds that the record is sufficient to demonstrate that the proposed construction project, combined with the Bluegrass Generation purchase, represent the least-cost resources to meet the Joint Applicants' capacity needs beginning in 2016. The Commission further finds that the proposed facilities are reasonable and will not result in wasteful duplication of utility facilities. The proposed facilities have the lowest net PVRR among all the alternatives that were considered.

Concerning the Environmental Intervenors' argument that the Joint Applicants failed to identify a least-cost plan that included all cost-effective DSM programs and that a more robust DSM portfolio would delay the Joint Applicants' need for capacity and/or reduce the amount of capacity needed, the evidence established that, even under a robust DSM portfolio that achieved one percent annual energy savings, the Joint Applicants' peak load would be reduced by only 125 MW. Compared with the Joint Applicants' total capacity need of 877 MW in 2016, the Environmental Intervenors' scenario would still leave the Joint Applicants needing 752 MW. Even taking into consideration the Joint Applicants' unopposed proposal to purchase the 495 MW Bluegrass Generation combustion turbines, the Joint Applicants would still be faced with a capacity shortfall of 257 MW and, because the Bluegrass Generation assets provide only peaking energy, Joint Applicants would experience a considerable energy shortfall of almost 3.2 million MWh.[60] Thus, even under Environmental Intervenors robust DSM scenario, construction of CR 7 would still be necessary.

Notwithstanding our finding above, the Commission does share the concern of Environmental Intervenors that the Joint Applicants have not adequately addressed one of the recommendations set forth in the ICF Louisville Gas and Electric Company/Kentucky Utilities Company DSM Program Review Report ("ICF Report").[61] In particular, the ICF Report recommended that the Joint Applicants commission a potential study or market characterization study to be used to help plan programs that capture savings where potential is greatest and/or most cost-effective.[62] Based on the market characterization study of the commercial sector, ICF also recommended that the Joint Applicants should develop additional DSM programs targeting the commercial

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[60] Rebuttal Testimony of David S. Sinclair ("Sinclair Rebuttal Testimony"), pp. 6-7.

[61] *See* Sinclair Rebuttal Testimony, Rebuttal Appendix A.

[62] ICF Report, p. 9, 75.

sector.[63] Although the ICF Report noted that the Joint Applicants continued to offer cost-effective programs, their DSM portfolio could improve its cost-effectiveness through additional commercial programs.[64] Accordingly, the Commission will direct the Joint Applicants to commission a potential or market characterization study as recommended in the ICF Report. We do, however, want to take this opportunity to recognize that the ICF Report indicated that the Joint Applicants' DSM portfolio contained many elements of best practices, including cost effectiveness, broad targeting, and flexible design.[65] We strongly encourage the Joint Applicants to continue with this approach and to leverage their corporate relationship with PPL Corporation to garner additional best practices that can be adopted.

As to Environmental Intervenors' argument that the Joint Applicants' RFP process produced a limited "array of renewable energy resource proposals," the Commission finds the Joint Applicants' RFP process to be reasonable. The RFP was sufficiently comprehensive and the six-week deadline provided reasonable notice to potential energy suppliers to produce a complete and comprehensive response. The Commission further finds that the evidence supports the Joint Applicants' proposal as being least-cost even when compared to a scenario which assumes Environmental

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[63] *Id.*

[64] ICF Report, p. 75.

[65] The Commission further acknowledges that the Joint Applicants proposed, and received approval for, a significant expansion of their DSM portfolio, totaling $263.8 million over a seven-year period. Joint Applicants' expanded DSM portfolio contains DSM and energy efficiency programs that were found to be cost-effective and broad based. *See* Case No. 2011-00134.

Intervenors' robust DSM position and purchasing the largest quantity of wind achievable from the RFP options.

With respect to Environmental Intervenors' argument that the Joint Applicants' modeling was skewed in favor of natural gas units due to the zero cost assigned to potential greenhouse gas regulations, the Commission finds such an assumption to be reasonable given the circumstances in the matter at hand. As the Joint Applicants point out, the EPA issued proposed New Source Performance Standards ("NSPS") on March 27, 2012, for new fossil-fueled power plants.[66] The proposed standard would apply a CO_2 emission limit of 1,000 lb/MWh to new generating units that do not have permits and start construction within 12 months of the proposal.[67] Joint Applicants' proposed facilities would not be affected by the proposed regulation because the Bluegrass Generation facilities are existing generating units and CR 7 is projected to have a CO_2 emission rate of about 800 lb/MWh. If the proposed NSPS is indicative of potential future greenhouse gas regulation, the cost-effectiveness of the proposed CR 7 and the Bluegrass Generation facilities would not be impacted. Given the specific type of generation technologies proposed in this matter, the Commission finds that the modeling of a carbon price would not have altered the outcome of this case. Moreover, although they contend that the Joint Applicants should consider a diverse portfolio of generation mix, Environmental Intervenors readily admit that natural gas should be a part of that generation mix if it is determined that natural gas represents the least cost

[66] Joint Applicants' Post-Hearing Brief, p. 25.

[67] *Id.*

alternative. The Commission is of the opinion that the natural gas facilities proposed herein are the least cost alternative.

SITE COMPATIBILITY CERTIFICATE

Joint Applicants indicate that there are good operational reasons to place the proposed CR 7 unit at Cane Run: (1) there is existing electrical transmission that the proposed CR 7 will be able to use; (2) using the existing Cane Run site, where 563 MW of existing coal-fired generation will be retired, will allow CR 7 to effectively "net out" of the Prevention of Significant Deterioration air permitting process that would be required if CR 7 were placed at the Joint Applicants' Brown Generating Station; and (3) having a geographical diversity of gas-fired generating units increases the overall reliability of the Joint Applicants' generating fleet by minimizing the impact of possible natural gas delivery disruption at a particular site. More significantly, the Joint Applicants' Site Assessment Report indicates that the Cane Run site was designed to accommodate additional generating units and that the addition of CR 7, while retiring the existing coal units, would not cause a negative impact to local property values, unduly increase traffic or noise, or materially change the visual impacts of the facility from current conditions.

The Commission finds that the Joint Applicants have satisfied the requirements of KRS 278.216 for the issuance of a Site Compatibility Certificate for CR 7.

IT IS THEREFORE ORDERED that:

1. Joint Applicants are granted a CPCN to construct a new 640 MW natural gas combined cycle combustion turbine unit at the Cane Run station and to purchase from Bluegrass Generation the natural gas simple cycle generation facilities, which include three turbines with a combined capacity of 495 MW in LaGrange, Kentucky.

2. Within 30 days of the completion of the construction of CR 7, Joint Applicants shall file with the Commission the actual cost of the construction.

3. Joint Applicants are granted a Site Compatibility Certificate to construct CR 7 at the Cane Run Station site in Louisville, Kentucky.

4. Within three months of the issuance of this Order, Joint Applicants shall commission a potential or market characterization study as recommended in the ICF Report.

5. Joint Applicants shall file with the Commission the potential or market characterization study within 30 days of the date it is completed and finalized.

6. Any documents filed in the future pursuant to ordering paragraphs 2 and 5 herein shall reference this case number and shall be retained in the utility's general correspondence file.

By the Commission

ENTERED
MAY 03 2012
KENTUCKY PUBLIC SERVICE COMMISSION

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