COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

AN ELECTRONIC EXAMINATION OF THE APPLICATION OF THE FUEL ADJUSTMENT CLAUSE OF KENTUCKY POWER COMPANY FROM NOVEMBER 1, 2020 THROUGH OCTOBER 31, 2022	)))))	CASE NO. 2023-00008

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 recording of the evidentiary hearing conducted on February 13, 2024 in this proceeding;

- Certification of the accuracy and correctness of the digital video recording;

- All exhibits introduced at the evidentiary hearing conducted on February 13, 2024 in this proceeding;

- A written log listing, inter alia, the date and time of where each witness' testimony begins and ends on the digital video recording of the evidentiary hearing conducted on February 13, 2024.

A copy of this Notice, the certification of the digital video record, and hearing log have been served upon all persons listed at the end of this Notice. Parties desiring to view the digital video recording of the hearing may do so at https://youtu.be/-e4Pjxm1KGU.

Parties wishing an annotated digital video recording may submit a written request by electronic mail to pscfilings@ky.gov. A minimal fee will be assessed for a copy of this recording.

Done at Frankfort, Kentucky, this 23rd day of April 2024.

Linda C. Bridwell
Executive Director
Public Service Commission of Kentucky

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CERTIFICATION

I, Candace H. Sacre, hereby certify that:

1. The attached flash drive contains a digital recording of the Formal Hearing conducted in the above-styled proceeding on February 13, 2024. The Formal Hearing Log, Exhibits, and Exhibit List are included with the recording on February 13, 2024;

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

3. The digital recording accurately and correctly depicts the Formal Hearing of February 13, 2024; and

4. The Formal Hearing Log attached to this Certificate accurately and correctly states the events that occurred at the Formal Hearing of February 13, 2024, and the time at which each occurred.

Signed this 16th day of April, 2024.

Candace H. Sacre
Candace H. Sacre
Administrative Specialist III

Stephanie Schweighardt
Stephanie Schweighardt
Kentucky State at Large ID# KYNP 64180
Commission Expires: January 14, 2027

Date:	Type:	Location:	Department:
2/13/2024	Public Hearing\Public Comments	Hearing Room 1	Hearing Room 1 (HR 1)

Witness: Josh Burkholder; Kim Chilcote; Randy Futral; Lerah Kahn; Tim Kearns; Lane Kollen; David Mell; Doug Rosenberger; Clint Stutler; Alex Vaughan; Brian West
Judge: Angie Hatton
Clerk: Candace Sacre

Event Time	Log Event	
9:07:48 AM	Session Started	
9:07:50 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	On the record in 2023-00008.
9:08:08 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Preliminary remarks.
9:09:28 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Entry of appearance of counsel, identify witnesses.
9:09:39 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Katie Glass, also appearing Ken Gish and Hector Garcia Santana, witnesses Alex Vaughan, Tim Kearns, Lerah Kahn, Kim Chilcote, Brian West, David Mell, Josh Burkholder, Clint Stutler, and Doug Rosenberger.
9:10:11 AM	Asst Atty General West	
	Note: Sacre, Candace	Mike West.
9:10:13 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Mike Kurtz, Jody Kyler Cohn, joint witnesses with AG, Lane Kollen and Randy Futral.
9:10:24 AM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Jeb Pinney, also Jason Colyer and Michael Crum and Sara Jankowski and John Rogness.
9:10:37 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Public notice.
9:10:55 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Public comments.
9:11:50 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Call witnesses.
9:12:04 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Lerah Kahn, Kim Chilcote, Josh Burkholder, David Mell, Doug Rosenberger, Clint Stutler, Alex Vaughan, Tim Kearns, and Brian West.
9:12:12 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Discussion of change in witnesses. (Click on link for further comments.)
9:12:39 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Witnesses are sworn.
9:13:10 AM	Atty Glass Kentucky Power - witness West	
	Note: Sacre, Candace	Direct Examination. Can you please state your name employer and position?
9:13:18 AM	Camera Lock Applicant Activated	
9:13:20 AM	Atty Glass Kentucky Power - witness West	
	Note: Sacre, Candace	Can you please state your business address?

9:13:30 AM	Atty Glass Kentucky Power - witness West		
		Note: Sacre, Candace	Did you cause to be filed into the record of this case rebuttal testimony?
9:13:35 AM	Atty Glass Kentucky Power - witness West		
		Note: Sacre, Candace	Do you have any corrections or updates to that testimony?
9:13:39 AM	Atty Glass Kentucky Power - witness West		
		Note: Sacre, Candace	If I asked you those same questions today, would your answers be the same?
9:13:45 AM	Atty Glass Kentucky Power - witness Chilcote		
		Note: Sacre, Candace	Direct Examination. Could you please state your name, employer, and position?
9:14:04 AM	Atty Glass Kentucky Power - witness Chilcote		
		Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony and responses to data requests?
9:14:13 AM	Atty Glass Kentucky Power - witness Chilcote		
		Note: Sacre, Candace	Did you cause to be filed into the record of 2022-00263 direct testimony?
9:14:19 AM	Atty Glass Kentucky Power - witness Chilcote		
		Note: Sacre, Candace	Do you have any corrections or updates to those answers?
9:14:34 AM	Atty Glass Kentucky Power - witness Chilcote		
		Note: Sacre, Candace	Subject to that update, if I asked you those same questions today, would your answers be the same?
9:14:41 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:14:48 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	And your business address, please?
9:14:55 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	Did you adopt the direct testimony, rebuttal testimony, and responses to data requests of Mr. Bishop in this case?
9:15:03 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	Did you also adopt the data request responses of Bishop in 2022-00263?
9:15:12 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	Do you have any corrections or updates to that testimony or responses?
9:15:27 AM	Atty Glass Kentucky Power - witness Kahn		
		Note: Sacre, Candace	Subject to that errata testimony or that correction, if I asked you the same questions today, would your answers be the same?
9:15:36 AM	Atty Glass Kentucky Power - witness Kearns		
		Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:15:54 AM	Atty Glass Kentucky Power - witness Kearns		
		Note: Sacre, Candace	And did you cause to be filed into the record of this case rebuttal testimony?
9:16:00 AM	Atty Glass Kentucky Power - witness Kearns		
		Note: Sacre, Candace	Did you also adopt the data request responses of Robert Jessee in this case?
9:16:06 AM	Atty Glass Kentucky Power - witness Kearns		
		Note: Sacre, Candace	Did you also cause to be filed into the record of 2022-00263 discovery responses and rebuttal testimony?
9:16:16 AM	Atty Glass Kentucky Power - witness Kearns		
		Note: Sacre, Candace	Do you have any corrections or updates to any of those documents?

9:16:20 AM	Atty Glass Kentucky Power - witness Kearns	
	Note: Sacre, Candace	If I were to ask you those same questions today, would your answers be the same?
9:16:26 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:16:38 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	And did you say your position?
9:16:44 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony and responses to data requests?
9:16:52 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	And did you also cause to be filed into the record of 2022-00263 responses to data requests?
9:16:58 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Do you have any corrections or updates to any of that information?
9:17:12 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Do you also have an update to your title?
9:17:29 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Do you also have an update to one of the confidential attachments that were filed in this case?
9:17:36 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Supplemental response. (Click on link for further comments.)
9:18:09 AM	Atty Glass Kentucky Power - witness Rosenberger	
	Note: Sacre, Candace	Subject to those corrections or updates, if I asked you those same questions today, would your answers be the same?
9:18:13 AM	Camera Lock Deactivated	
9:18:18 AM	Atty Glass Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:18:32 AM	Atty Glass Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony and responses to data requests?
9:18:38 AM	Atty Glass Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Do you have any updates or corrections to that information?
9:18:42 AM	Atty Glass Kentucky Power - witness Stutler	
	Note: Sacre, Candace	If I were to ask you those same questions today, would your answers be the same?
9:18:46 AM	Atty Glass Kentucky Power - witness Burkholder	
	Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:19:03 AM	Atty Glass Kentucky Power - witness Burkholder	
	Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony?
9:19:07 AM	Atty Glass Kentucky Power - witness Burkholder	
	Note: Sacre, Candace	Do you have any corrections or updates?
9:19:10 AM	Atty Glass Kentucky Power - witness Burkholder	
	Note: Sacre, Candace	If I were to ask you those same questions today, would your answers be the same?
9:19:15 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?

9:19:29 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	And your position, please?
9:19:44 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony and responses to data requests?
9:19:51 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	And have you also adopted the data request responses of Paul Massie in 2022-00263?
9:19:59 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	Do you have any corrections or updates to that information?
9:20:03 AM	Atty Glass Kentucky Power - witness Mell	
	Note: Sacre, Candace	If I were to ask you those same questions today, would your answers be the same?
9:20:08 AM	Atty Glass Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Direct Examination. Can you please state your name, employer, and position?
9:20:26 AM	Atty Glass Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Did you cause to be filed into the record of this case direct testimony, rebuttal testimony, and responses to data requests?
9:20:34 AM	Atty Glass Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Did you also adopt the testimony and data request responses of Jason Stegall in 2022-00263?
9:20:42 AM	Atty Glass Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Do you have any corrections or updates to that information?
9:20:46 AM	Atty Glass Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	If I were to ask you those same questions today, would your answers be the same?
9:20:50 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Conclude direct?
9:20:54 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Cross examination order. (Click on link for further comments.)
9:21:21 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Cross Examination. Are you familiar with Kollen testimony that the PUE sets a line of demarcation between economy and non-economy purchases?
9:21:34 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Do you alternatively refer to this line of demarcation as an arbitrary price limiter in your testimony?
9:21:41 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Would you say it's self-explanatory that the peaking unit equivalent is based on the operation of a peaking unit?
9:22:15 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	I guess I'd like to understand the use of the word arbitrary, what makes the PUE an arbitrary price limiter?
9:23:19 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	You have your rebuttal testimony in front of you, right?
9:23:24 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Turn to page 16 and read starting on line 7 through 14?

9:23:58 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	The last two sentences as well, through line 14?
9:24:29 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Run time of one hour minimum, startup costs included every hour, one hour maximum and not minimum?
9:25:35 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Would not agree startup costs included every hour no scenarios carry over from one hour to next?
9:26:32 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Indicated inclusion of startup costs approved in 2017-00179?
9:27:25 AM	Asst Atty General West	
	Note: Sacre, Candace	Handed you pages 55 and 56 Commission Order Jan 18 2018 in 2017-00179, ask made AG Hearing Exhibit 1. (Click on link for further comments.)
9:27:26 AM	ATTY GENERAL HEARING EXHIBIT 1	
	Note: Sacre, Candace	ASST ATTY GENERAL WEST - WITNESS VAUGHAN
	Note: Sacre, Candace	COMMISSION ORDER 2017-00179 JAN 18 2018
9:28:20 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Read entire section, Peaking Unit Equivalent Calculation, the whole section?
9:29:41 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Last sentence, what talking about when say Commission approved startup costs?
9:29:59 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Order say whether startup costs be included in each hour?
9:30:38 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Confirm, rebuttal, page 11, say PUE operates as proxy, not CT unit?
9:31:09 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Page 12, PUE does not represent reality?
9:31:26 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	2017-00179 Order, section, reading (click on link for further comments), accurate recitation?
9:31:55 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Kentucky Power requested Commission include firm gas service costs in calculation of PUE?
9:33:21 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Characteristic of real CT that company requested Commission consider?
9:33:40 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Commission disagreed, reading (click on link for further comments), sounds like proposal and Commission decision-making on PUE considering how actual CT operates?
9:35:05 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	When says, reading (click on link for further comments), testimony not talking how CTs operate?
9:35:29 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Where should Commission draw line units should consider and those not consider?
9:36:51 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	But not willing to draw line here?
9:38:30 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Ceredo 1 unit of affiliate went to and made comparison just referenced?
9:38:39 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Page 12, rebuttal, lines 6 through 12, read for me?

9:39:04 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Next two sentences?
9:39:30 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Concept not make sense, PUE in general?
9:40:12 AM	Asst Atty General West - witness Vaughan	
	Note: Sacre, Candace	Should scrap PUE since not make sense?
9:40:32 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Mr. Kurtz?
9:40:47 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Cross Examination. In 2000, who proposed the PUE?
9:41:00 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Kentucky Power propose because hurt or help?
9:41:31 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Kentucky Power proposed it, just indicated why, complained not have peaking unit, unfair base line of demarcation between economy and non-economy on baseload units, fully recoverable?
9:42:06 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Testified about it, were right, way to raise line of demarcation in 2000?
9:42:45 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	In 2005, aware Kentucky Power dropped PUE?
9:43:01 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	In 2017, proposed three adjustments get PUE higher?
9:43:33 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Marked as KIUC Hearing Exhibit 1 from 2017 case
9:43:34 AM	KIUC HEARING EXHIBIT 1	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	VAUGHAN TESTIMONY FROM 2017 CASE
9:44:14 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Testimony from 2017 propose three changes increase PUE?
9:44:29 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Startup costs, firm gas transportation, and variable O&M?
9:44:53 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 33, lines 5-14, original calculation, gas index proposed by company in 2000 was approved?
9:45:14 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 34, describe rationale for each of increases, read line 1 on page 34 through line 12?
9:46:39 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	How square that with page 11, line 11, reading?
9:47:48 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	At end of KIUC Exhibit 1 is Exhibit 8, turn to that?
9:48:02 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Firm gas adjustment calculation denied by Commission?
9:48:11 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Adopted startup costs of $30 a megawatt hour?
9:48:16 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Said very clear a by-hour calculation, looks to me is by month, where clear this is by hour?
9:49:08 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	If so clear, why not say startup costs be by hour?
9:49:33 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 13-16, this hypothetical peaking unit nothing to do with Ceredo Unit 1?

9:50:09 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Used as basis for actual cost of CT, used Ceredo 1?
9:50:38 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Exhibit sponsored by Stegall.
9:50:38 AM	KIUC HEARING EXHIBIT 2	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	KENTUCKY POWER 2022-00036 RESPONSE STAFF POST-HEARING DATA REQUEST AUG 8 2022 WITNESS: STEGALL
9:51:20 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Staff asked how get variable O&M and how get startup costs for proxy, answer page 3, exhibit from 2017 just talked about?
9:52:12 AM	Atty Gish Kentucky Power	
	Note: Sacre, Candace	Have workpapers from AEV-8. (Click on link for further comments.)
9:52:48 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 3 your exhibit from 2017 rate case?
9:52:57 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 4 and 5 shows calculation of $3.48 per megawatt hour variable O&M?
9:53:08 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	See unit name Ceredo?
9:53:24 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Rebuttal testimony that Ceredo not actual proxy, how square that?
9:54:28 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Turn page, Ceredo Unit 1, answer be same?
9:55:19 AM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Examination. Ceredo chosen at random?
9:56:10 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Cross Examination (cont'd). Page 9, rebuttal, line 17, other variable costs, purpose of statement?
9:57:00 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Isn't that what FAC regulation does?
9:57:31 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Variable O&M gas units not recovered in environmental surcharge, are base rate items?
9:57:44 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Scrubber reagent and consumables characterized as variable O&M?
9:58:10 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Agree fuel adjustment clause recovers Account 151 fuel, not variable O&M?
9:58:18 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Where get $20 megawatt hour variable O&M cost of Mitchell?
9:58:58 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Agree last ten years variable O&M costs Mitchell went from $2.76 megawatt hour to $5.10 megawatt hour?
9:59:37 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Are witness how PUE calculation works?
9:59:58 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	This be KIUC 3.
9:59:59 AM	KIUC HEARING EXHIBIT 3	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 ITEM 3 ATTACHMENT 6 TAB 1 OF 7: 10-2022

10:00:50 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Company goes through calculation every hour every day every year that determines how much PUE disallowance be?
10:01:08 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Familiar with document as what filed?
10:01:20 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Hourly calculation, chose Oct 10, see highlighted hour of 20?
10:01:47 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Correct internal load of Kentucky Power in that hour 620 megawatts?
10:01:57 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Load was met column 3 purchases, equals native load of 620?
10:02:23 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	During this hour, 100 percent of native load was supplied by PJM market purchases?
10:02:33 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Purchase price from PJM $107 megawatt hour?
10:02:41 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 2 and 3 shows none of plants operated during October?
10:03:06 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 4, goes through PUE calculation, let me walk through it, (click on link for further comments)?
10:03:43 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	PUE $92.448 for that hour?
10:03:52 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Got $92 PUE for that hour?
10:04:15 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	$92 PUE less than $107 actual purchase, disallowance of $8,912?
10:04:41 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Customers charged $92 megawatt hour even though power plants not operating lower cost than $92?
10:05:01 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	$92 megawatt hour times 611 megawatts recovered from customers in FAC?
10:05:27 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	If were get rid of PUE, customers would have paid $107 market purchase?
10:05:51 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Applied to 611 megawatts, all purchases to meet native load that hour?
10:06:33 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Last exhibit, KIUC 4. (Click on link for further comments.)
10:06:34 AM	KIUC HEARING EXHIBIT 4	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 ITEM 3 ATTACHMENT 2 TAB 1 OF 7: 6-2022
10:07:23 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Same math, different hour, Jun 2 2022, see highlighted?
10:07:44 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Internal load 809 megawatts?
10:07:55 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	809 megawatts met by column 3?
10:08:12 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Net available generation, line 6, 945 megawatts, what net available generation mean?

10:08:25 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Big Sandy not available at all?
10:08:44 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Mitchell 1 was available?
10:08:59 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Amount available Mitchell 1 385 megawatts?
10:10:12 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Whole plant, think available 385 Mitchell 1 395 Mitchell 2 plus 165.45 of Rockport 2, equals 945, net available on page 1?
10:10:55 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Page 4 picks up same numbers, purchases assigned native load page 4 360.87, 361 on first page, does that match?
10:11:17 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Purchase price $114 megawatt hour?
10:11:22 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	PUE was $121 per megawatt hour?
10:11:29 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Mitchell 1 fuel cost $24.81 megawatt hour?
10:11:52 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Mitchell 2 $24.28 megawatt hour?
10:11:58 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Rockport 2 $37.10 megawatt hour?
10:12:07 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	No elimination from FAC that hour?
10:12:33 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Why AEP or Kentucky Power only buying 360 megawatts from PJM?
10:14:07 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Agree FAC intended result in reasonable fuel costs for consumers?
10:14:58 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	What good do for consumers pay for baseload coal power plants cost of $173 million a year, customers paying as hedge, what good for customers if power plants not run?
10:16:46 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Agree two-year review period Kentucky Power spent $238.7 million on market purchases?
10:17:36 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Kollen direct, 2023-00008 case, line 8 on page 4, $238.7 million purchases?
10:18:02 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Believe number correct?
10:18:38 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	During review period, purchase price was $47.71 megawatt hour?
10:19:04 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Market prices did, too?
10:19:08 AM	Atty Kurtz KIUC - witness Vaughan	
	Note: Sacre, Candace	Why not running full out and selling off system?
10:20:30 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Procedural discussion. (Click on link for further comments.)
10:21:57 AM	Session Paused	
10:35:10 AM	Session Resumed	
10:35:14 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Back on the record, and still in cross examination of Mr. Kurtz.

10:35:21 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Cross Examination. Testified in rebuttal operation of fuel adjustment clause, page 5, cite 807 KAR 5:056?
10:35:54 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Make observation AG/KIUC could constitute retroactive ratemaking?
10:36:21 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Familiar with regulation, you cited to it, hand you a copy of it?
10:37:17 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Object. (Click on link for further comments.)
10:37:18 AM	KIUC HEARING EXHIBIT 5	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS WEST
	Note: Sacre, Candace	TITLE 807 CHAPTER 005 REGULATION 056
10:37:32 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Familiar with regulation?
10:37:41 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Aware enabling legislation 278.030, fair just and reasonable rates, and 278.030(2), adequate efficient reasonable service?
10:37:56 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Object. (Click on link for further comments.)
10:38:00 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Page 1 of regulation highlighted?
10:38:09 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Kentucky Power has new fuel adjustment every month?
10:38:28 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Implement FAC unilaterally, six-month and two-year review cases?
10:38:44 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Doing this for long time?
10:38:48 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	How long with Kentucky Power?
10:38:56 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Reading (click on link for further comments), reasonableness basic tenet of regulation?
10:39:32 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Objection. (Click on link for further comments.)
10:40:19 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Have an answer to that question?
10:40:23 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Reasonableness important in FAC review case?
10:40:55 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Familiar with Mitchell FAC disallowance Order from 2015?
10:41:10 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Assuming Commission disallowed $54 million total and ordered $13 million refunded, bear on AG/KIUC position consistent with Commission practice or retroactive ratemaking?
10:41:45 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Object. (Click on link for further comments.)
10:41:57 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	What Kentucky Power do if Commission suspended fuel adjustment reg for Kentucky Power?
10:42:46 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Not my question, my question was what Kentucky Power do if Commission suspended operation FAC and had you recover all fuel/purchase power costs in base rates?

10:43:14 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Could recover through base rates and manage costs and manage PJM if FAC suspended?
10:43:35 AM	Atty Glass Kentucky Power	
	Note: Sacre, Candace	Object. (Click on link for further comments.)
10:44:01 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Could recover in base rates if FAC suspended?
10:44:17 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	Here for Vaughan cross?
10:44:38 AM	Atty Kurtz KIUC - witness West	
	Note: Sacre, Candace	If Commission said hard to audit on hourly basis, turn over to you to manage in base rates, could do that?
10:45:27 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Move to admit?
10:45:33 AM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Move KIUC Exhibit 1 through 5.
10:45:34 AM	Atty Gish Kentucky Power	
	Note: Sacre, Candace	Highlighting for ease of reference. (Click on link for further comments.)
10:45:35 AM	KIUC HEARING EXHIBIT 1	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	VAUGHAN TESTIMONY FROM 2017 CASE
10:45:36 AM	KIUC HEARING EXHIBIT 2	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	COMMISSION ORDER 2017-00179 JAN 18 2018
10:45:37 AM	KIUC HEARING EXHIBIT 3	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 TAB 1 OF 7: 10-2022
10:45:38 AM	KIUC HEARING EXHIBIT 4	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS VAUGHAN
	Note: Sacre, Candace	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 TAB 1 OF 7: 6-2022
10:45:39 AM	KIUC HEARING EXHIBIT 5	
	Note: Sacre, Candace	ATTY KURTZ KIUC - WITNESS WEST
	Note: Sacre, Candace	TITLE 807 CHAPTER 005 REGULATION 056
10:46:02 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Staff?
10:46:10 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Cross Examination. 2023-00008, Attachment 2, Response to Staff First, Item 4, Mitchell low sulfur 2022 purchase, how conducts analysis, explain what meant by Btu?
10:48:25 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Heat content, how calculated?
10:49:00 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Coal price, per ton?
10:49:06 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	What be paying for that coal?
10:49:20 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Deliveries to Mitchell primarily by barge?
10:49:40 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Belt, high sulfur?
10:50:24 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Transportation, costs included in coal play immediately to left?

10:51:01 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Believe read Kentucky Power utilize existing transportation contract another utility may have?
10:51:27 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Rate for that deals with distance and loading points?
10:51:45 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Pounds of SO2?
10:52:05 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Sulfur percentage and ask percentage?
10:52:10 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Inputs provided to Kentucky Power?
10:52:10 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	What is quality adjustment?
10:53:16 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Higher than SO2 more expense borne by company to remove?
10:53:34 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Removing sulfur chemical reagents used?
10:53:56 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Other costs involved?
10:54:19 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Including in price for coal, delivered costs, results MMBtu costs, purpose for evaluating bids?
10:55:38 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Cost of reagents and where recovered, included in evaluating costs, recover fuel burned through FAC, separate calculation running through FAC?
10:57:00 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Reagents we are talking about?
10:58:35 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	In evaluation sheets, severance tax removed?
10:59:02 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Who makes filing for Form A FAC filings?
10:59:51 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Two monthly filings, Form A, simpler form?
11:00:33 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Form A, prorating of FAC factor or goes into effect Mar 1?
11:01:00 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Describe what happens between expense month and true-ups a month or two later, what gets clarified?
11:02:00 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Not estimate PUE?
11:02:25 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	PUE is line, anything above cost considered noneconomic purchase?
11:02:33 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Anything below is economic purchase and recovered through FAC, dividing line?
11:03:10 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Kentucky Power proposing to reset FAC base rate?
11:03:30 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Which month proposing use?
11:03:58 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Anything transpiring lead Kentucky Power propose different?
11:05:27 AM	Exec Atty Advisor Pinney - witness Kahn	
	Note: Sacre, Candace	Table, where was that?

11:05:30 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Gas transmission and sales, Kentucky Power firm gas transmission contracts for natural gas generating unit?
11:06:35 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	With one company?
11:06:49 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Direct, Stutler, page 11, reading, prior to that, all purchases spot purchases?
11:08:16 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	If fixed natural gas price, physical hedge or more natural?
11:08:44 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Ability to store natural gas?
11:09:06 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Actual storage on pipeline?
11:09:47 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	When looking at storage, pay for that?
11:10:06 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Direct, page 12, what happens if something changes in meantime, ability to get gas, issue with Elliott in PJM, come into holiday weekend, nobody to call, have ability to procure gas on long weekend?
11:12:27 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Big Sandy converted unit?
11:12:42 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	How long take to fire up Big Sandy?
11:13:07 AM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Do you know?
11:13:43 AM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	When get notification at 1 pm, for day-ahead market?
11:14:06 AM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	If get 20 hours, 10 am what looking at?
11:14:31 AM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	At that point, available for full dispatch, price curve starts to go up?
11:15:09 AM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Big Sandy not baseload unit, intermediate load unit?
11:16:21 AM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Kentucky Power/AEP policy in place for procurement of gas on weekends?
11:17:00 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Coal procurement two-year period under review, at what point Kentucky Power coal supply at Mitchell issue?
11:19:17 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Still talking about Sept RFP?
11:21:28 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Talking about operating company?
11:21:36 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Making purchases on behalf of a lot of AEP entities?
11:21:44 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Kentucky Power 50 percent interest in Mitchell?
11:21:48 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Other utility Wheeling Power?
11:21:54 AM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Making purchases of power on behalf of Kentucky Power and Wheeling Power?

11:22:23 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	When did PJM start discussing adequacy of fuel supplies?	
11:23:15 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Decisions for coal purchases not made by individual utility, operating company may have say?	
11:26:40 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	How changes to Manual 13, Stegall?	
11:27:11 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Stegall till with company?	
11:27:29 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	How changes made to Manual 13?	
11:28:11 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	AEP member of PJM?	
11:28:25 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Incorrect say large utility of PJM?	
11:28:44 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Does AEP get seat at table?	
11:29:22 AM	Exec Atty Advisor Pinney - witness Burkholder		
	Note: Sacre, Candace	Burkholder, additions to that?	
11:30:06 AM	Exec Atty Advisor Pinney - witness Burkholder		
	Note: Sacre, Candace	Last part?	
11:30:26 AM	Exec Atty Advisor Pinney - witness Burkholder		
	Note: Sacre, Candace	Subject to approval by several committees?	
11:31:28 AM	Exec Atty Advisor Pinney - witness Burkholder		
	Note: Sacre, Candace	Who members of market reliabilty committee?	
11:31:43 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Meetings held at PJM when coal might become an issue?	
11:32:11 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Documentation AEP has?	
11:33:32 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Meetings conducted per Robert's Rules?	
11:33:49 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Post-hearing ask for documents?	
11:34:09 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Talking about load-serving entities?	
11:34:52 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	For Kentucky Power, zone of PJM, AEP East Zone?	
11:35:44 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Familiar with app PJM has?	
11:35:59 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	What happens show zone but press on points and give different price, what talking about?	
11:36:47 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Ten-day rule, still in effect?	
11:37:08 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	PJM amended Manual 13 to implement ten-day rule or 240 hours, increased from minimal hours to 240 hours?	
11:37:50 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Familiar with Manual 13?	
11:38:05 AM	Exec Atty Advisor Pinney - witness Vaughan		
	Note: Sacre, Candace	Post-hearing ask for PJM Manual 13?	
11:38:26 AM	POST-HEARING DATA REQUEST		
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS VAUGHAN	
	Note: Sacre, Candace	PJM MANUAL 13	

11:39:05 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Tell me what 10-day rule did, what is rule?
11:40:53 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Intervals, hot or cold weather alert?
11:41:13 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	How utility functions in PJM, fixed resource requirement?
11:41:20 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Reliability pricing model?
11:41:28 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	As FRR, Kentucky Power have leeway in deciding what units bids into capacity auction?
11:42:27 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	In base residual entity, generator owner commit units into auction?
11:42:41 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Kentucky Power have to include all generating units?
11:43:39 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	When offer into market, can make a lot of money?
11:44:02 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Ideas how things operate at PJM, all must offer?
11:45:21 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Must offer status, planned outage, does utility run risk of performance penalties?
11:46:23 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Winter Storm Elliott, very unpleasant?
11:46:24 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Same true for maintenance outage?
11:46:28 AM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Point where maintenance outage extend too long and classified as forced outage?
11:47:32 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Unit in forced outage status, how calculate otherwise been dispatched?
11:48:30 AM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Extending planned outages, something report to PJM?
11:49:19 AM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Where can those be found, PJM Manual apply?
11:50:18 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Ten-day rule, Vaughan direct, page 5, 21-23, and page 6, 1-4, Stegall direct, page 5, lines 12-17, think say same thing?
11:50:56 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	When discussing ten-day rule, reading (click on link for further comments), moving unit into emergency status at discretion of PJM or automatic?
11:52:48 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	117 per unit?
11:52:55 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Forced outage completely running out of coal or below ten days?
11:53:10 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	What does maximum emergency status mean?
11:54:06 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Employed by AEP?
11:54:22 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Have insight into operation the other utilities?

11:54:37 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Other utilities aware of?
11:54:57 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Any of AEP operating companies run afoul of ten-day rule?
11:55:44 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Each unit might have different circumstance?
11:56:03 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Like Rockport gets Powder River Basin coal?
11:56:15 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Mitchell mix, some different requirements?
11:56:56 AM	Exec Atty Advisor Pinney - witness Vaughan and Chilcote	
	Note: Sacre, Candace	Some different blend, affect coal conservation strategy?
11:57:39 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Penalties, forced outage, different ones fall below ten days, PJM established timeline, performance penalties?
11:58:31 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Forced outage fines not fun?
11:58:48 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Asked AEP units run afoul of ten-day rule, know any units in PJM run afoul of rule?
11:59:10 AM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Independent power producers, merchants?
11:59:20 AM	Vice Chairman Hatton	
	Note: Sacre, Candace	Lunch break until 1 o'clock.
12:00:05 PM	Session Paused	
1:06:13 PM	Session Resumed	
1:06:22 PM	Vice Chair Hatton	
	Note: Sacre, Candace	Back on record
1:06:52 PM	Via Presentation Activated	
1:07:09 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Cross Examination. Staff First, Item 3, confirm day's supply calculated by tons in storage and dividing by full load burn rate?
1:07:46 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	And it's 24 hours full load?
1:08:01 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	With nothing coming in?
1:08:09 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Response, Staff Second, Item 6, Attachment 2, Dec 2021 to Jan 2022, inventory high sulfur increases, days at full load burn decrease, explain why?
1:10:33 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Maybe change in formula?
1:10:45 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Showing formula, reading (click on link for further comments), see that?
1:11:02 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	For Dec, and in Jan changes, reading (click on link for further comments), increase denominator and reduce days of inventory?
1:12:02 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	A recalculation every year, variety of factors?
1:12:09 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	When make change to formula, look retroactively and reassess or something perspective?

1:13:11 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	During review period, different target levels for low sulfur and high sulfur coal?
1:13:26 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Thirty days for low sulfur and 15 days for high sulfur?
1:13:32 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Why difference?
1:14:34 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	If available 15 days and 30 days full burn, forget mind to mouth with conveyor belt for high sulfur, maximum burn limited to lowest number there?
1:15:24 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	During period in review, testimony one of Mitchell units was must-run, reason run at higher percentage high sulfur?
1:15:52 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	If can adjust blends, adjust a little bit so extend life stockpile which have less?
1:16:48 PM	Via Presentation Deactivated	
1:17:23 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	High sulfur across street?
1:17:27 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Not worry about offloading, having personnel?
1:17:53 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Constraints from adjacent mine, what those?
1:18:50 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	When change target inventory levels, how frequently occur?
1:19:10 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Operating companies have a say?
1:19:56 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	When Kentucky Power adjust stockpile levels?
1:20:48 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Obligations to take coal deliveries?
1:20:59 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Operating companies had say, how affect coal procurement in 2018 2019 and 2020, looking at contracts, just bid a 15-day supply?
1:22:05 PM	Exec Atty Advisor Pinney - witness Chilcote and Rosenberger	
	Note: Sacre, Candace	How coal stockpiles calculated?
1:23:41 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Been instance when had to make adjustments to days, significant?
1:24:48 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Scales when unloaded and into plant, how does blending occur?
1:25:32 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Physical explanation how gets blended, two conveyors going in and get blended somewhere and go in?
1:26:13 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Speed of the conveyor belt where talk about blending, how it would be done?
1:26:41 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Kentucky not have minimum coal reserve requirement?
1:27:46 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Any other states have requirements for minimum coal reserves?
1:28:28 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Fifty-fifty ownership of Mitchell, same requirement apply to coal used for Kentucky Power?

1:28:39 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	But that under contract, not on ground?
1:28:43 PM	Exec Atty Advisor Pinney - witness Chilcote, Kearns, Vaughan	
	Note: Sacre, Candace	Significant drawbacks having coal piles in physical reserves?
1:31:10 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	If have large coal stockpile, why three years of coal, not seem reasonable?
1:31:25 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	When company recover cost of coal?
1:32:21 PM	Exec Atty Advisor Pinney - witness Vaughan and Kahn	
	Note: Sacre, Candace	When have inventory and just sitting there is a rock with carrying charge and then turns into something real?
1:32:44 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Spreadsheet, look at Aug Sept Oct 2021 stockpiles fell below target 15-day, increased burn or supply constraints?
1:32:57 PM	Via Presentation Activated	
1:34:00 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Historical knowledge either Mitchell shut down out of coal?
1:34:26 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Discussed May 14 coal solicitation?
1:34:37 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Responses to that?
1:35:29 PM	Exec Atty Advisor Pinney - witness Kahn, Vaughan, and Chilicote	
	Note: Sacre, Candace	Coal inventory, PSC ever disallowed cost having too much coal on ground?
1:36:12 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Examination. Debated but never denied to anyone's memory?
1:36:50 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Cross Examination (cont'd). More than conversation in base rate cases?
1:36:58 PM	Exec Atty Advisor Pinney - witness Vaughan and Chilcote	
	Note: Sacre, Candace	Monitoring of stockpiles, always reported to PJM?
1:37:30 PM	Atty Gish Kentucky Power	
	Note: Sacre, Candace	Citation to exhibit. (Click on link for further comment.)
1:38:09 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Full load burns on inventory level, levels reported to PJM, monthly inventory levels what was reported?
1:39:00 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	The other chemicals?
1:39:01 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS CHILCOTE
	Note: Sacre, Candace	REPORTING TO PJM
1:39:18 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	When reporting inventory levels, is it past week or forecasted for next week?
1:39:30 PM	Via Presentation Deactivated	
1:39:36 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Neither in past or future, just now?
1:39:43 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Coal RFPs, where are decisions made to issue RFP, gears starts moving and who moving?
1:39:50 PM	Via Presentation Activated	

1:40:21 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Not need high sulfur coal at Mitchell, issue RFP systemwide, tailored to delivery point?
1:40:22 PM	Via Presentation Deactivated	
1:42:36 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	How quickly RFP be issued?
1:43:15 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Testified Sept 2021 RFP shorter response time?
1:43:51 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Examination. What time period was this?
1:43:57 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Cross Examination (cont'd). Still have to act expeditiously, period not know Kentucky Power issued full solicitations?
1:44:26 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	From decision accept bids, how long to enter into contract?
1:45:26 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Rule of thumb once execute contract coal start showing up?
1:45:44 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Terms also say need coal by this date?
1:45:55 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Start dates vary depending upon needs and how far away?
1:46:29 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Are those written or oral, spot contracts?
1:47:10 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	2022-00036, Response, Commission First, Item 4, Attachment 1, Footnotes 1, 2, and 3, see those?
1:48:03 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	First footnote, seller withdrew or modified after RFP, explain?
1:48:58 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	If refer to 2022-00263, Response, First Request, Item 4, Attachment 1, same information, different dates, answers going to be the same?
1:49:39 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	What if says coal mines not in production, what mean?
1:51:15 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	2023-00008, Response, First Request, Item 4, Attachment 1, similar information, same question footnotes listed, why no vendors for high sulfur?
1:52:31 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Not know if due diligence when looking at procurement sheets?
1:52:55 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Northern App where low sulfur coal?
1:53:00 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Central?
1:53:05 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Mitchell located in Northern App?
1:53:10 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS CHILCOTE
	Note: Sacre, Candace	PROVIDE SOLICITATIONS IN CASE NOS. 2020-00236, 2022-00263, AND 2023-00008.
1:53:11 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Post-hearing DR for solicitations 2020-00236, 2022-00263, and 2023 -00008.
1:53:50 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Amendments to coal procurement process?

1:54:36 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Changes in written policies and procedures or within parameters make certain decisions?
1:54:50 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	During period under review, problems with delivery with any contracts?
1:56:04 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Verification of force majeure reasons why?
1:56:08 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Coal prices high, oh, no, force majeure, can't have it?
1:56:26 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Litigation during period of review with any suppliers?
1:56:35 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Will ask in DR, for two-year period under review, identify contracts under which receiving coal.
1:56:36 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS CHILCOTE
	Note: Sacre, Candace	FOR TWO-YEAR REVIEW PERIOD, IDENTIFY CONTRACTS UNDER WHICH KENTUCKY POWER RECEIVING COAL
1:56:52 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Looking earlier attachment, one included unsolicited offer?
1:57:04 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Only one, are you familiar, was it significant?
1:57:37 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Kentucky Power sought authority to sell its coal?
1:58:00 PM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Accept was case fled 2017-00446 in which Kentucky Power requested authority to sell 200,000 tons of high sulfur coal, Commission authorized it, a long time ago?
1:59:15 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Looking for coal, have a Rolodex, how find these people?
2:00:17 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Responses or was Feb 2022 unsolicited response, fell outside normal RFP process?
2:00:35 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	In response to written RFP?
2:00:39 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Less need coal, need it now, versus issuing an RFP?
2:01:25 PM	Exec Atty Advisor Pinney - witness Chilcote	
	Note: Sacre, Candace	Adder, drawing attention to Vaughan direct testimony this case, page 9, line 6-14, Stegall direct 2022-00263, page 9, lines 10-17, discussion how costs established market-based curve and cost-based curve?
2:02:18 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Subject to rules both PJM and FERC?
2:02:26 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	FERC not looking at independently, approving rules in tariff, and PJM enforcing?
2:02:40 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Quote, reading (click on link for further comments), give examples what opportunity are?
2:05:12 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Rules associated what considered opportunity cost or what inputs for market-based offer are?

2:06:55 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	PJM Manual 15, energy market opportunity costs and cost policy, come into play when calculating opportunity costs market-based curve?
2:07:51 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	In testimony, say market-based offer allows other factors, limit on what include in market-based offer?
2:08:17 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Page 11 of testimony, lines 11-23, discuss opportunity cost to customers on market curve and the adder being used to be dispatched only in hours?
2:09:11 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Mitchell running economic minimum means picked up day ahead or bid in as must-run?
2:10:01 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Ramp up, not talking starting from nothing?
2:10:15 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Said earlier committed units into capacity auction, must offer unless on outage?
2:10:30 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Offer day-ahead market and just discussed ability to ramp up, market decides that or PJM decides on dispatch model?
2:11:35 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Level of coordination, do op-cos have say in policies, just testified to that?
2:12:12 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	One of Mitchell units reserve shutdown, not burning any fuel, not spinning?
2:12:40 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Available but not operating, has to be available unless outage?
2:13:05 PM	Exec Atty Advisor Pinney - witness Stutler	
	Note: Sacre, Candace	Testimony before Big Sandy, when PJM notify Kentucky Power Mitchell units cleared day-ahead market?
2:13:20 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	At that moment, when you find matches and light things, how long take meet offer?
2:13:25 PM	Exec Atty Advisor Pinney - witness Rosenberger and Vaughan	
	Note: Sacre, Candace	Because is day-ahead and going to be real-time, anticipate certain period of time, but real-time market margin of error when ramp up?
2:14:47 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Once unit dispatched, level of dispatch vary, above economic minimum vary upon what PJM requesting?
2:15:01 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Congestion over here, accurate way to say that?
2:15:19 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Matter how long takes unit to come up, reserve shutdown for a day versus two versus three, affect timing come back online?
2:15:54 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Direct, page 12, lines 20-22, discuss company, is Kentucky Power or Service Company?
2:16:41 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Might apply individually to one of op-cos, but the company here does it refer to Kentucky Power or Service Corporation?

2:17:05 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	For purposes of Kentucky Power, since 50 percent owner Mitchell with Wheeling, coordination when looking at offers?
2:18:14 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Proprietary software, what factors take into consideration when forming those calculations?
2:19:58 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Proprietary software be provided to Commission?
2:20:02 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Something tackle later on in DR, ask question in post-hearing data request. (Click on link for further comments.)
2:20:03 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS VAUGHAN
	Note: Sacre, Candace	PROVIDE PROPRIETARY SOFTWARE
2:21:02 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	2023-00008 Response, Staff Second, Item 2, discusses formation of the adder committee, when formed?
2:22:44 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Each op-co have representative?
2:22:51 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Chilcote part of that decision?
2:22:56 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Adjustments to offer curve, monthly meeting, adder during period of time applied daily?
2:23:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	How making daily determinations?
2:26:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Any formal records of monthly meetings?
2:26:42 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Will check and, if not, have a request for it. (Click on link for further comments.)
2:26:52 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Stick with your testimony, page 14, lines 9-13, if company not implemented coal conservation increment strategy, Mitchell units out of coal, forced outage, helped avoid forced outage days?
2:27:50 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Review period, six-month period 2023-00008 or two-year review period?
2:28:30 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Under what scenarios Mitchell units run out of coal?
2:31:22 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Variability on coal burn, how calculate what coal burned without adder?
2:34:01 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Is that too complicated or not of any value?
2:34:38 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Backcast, look back to see if had bid in, burned full on this day?
2:34:54 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Are calculations in record?
2:35:00 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	If not, might ask post-hearing data request for that.
2:35:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Been changes to PJM policies, talk about ELCCs tied into same thing?

2:36:04 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Have effect on coal procurement or fuel procurement for op-cos?
2:36:37 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Watched video other cases, Duke said affect way operate?
2:36:59 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	No effect on fuel procurement planning, anything like that?
2:37:10 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Response, Commission Second, Item 2, Attachment 1, is this what reflected here, could have different prices, illustration of approach?
2:38:26 PM	Via Presentation Activated	
2:39:34 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	PJM have any say which units may have adder?
2:40:00 PM	Via Presentation Deactivated	
2:40:05 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Same data request, Item 3, all op-co coal units East Zone for PJM?
2:41:00 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	And those West companies as well?
2:41:12 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Confirm adder used, adder strategy implemented at each of units?
2:42:30 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Still put negative adder on there, not a must-run, still economic dispatch?
2:43:02 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Making value judgment, better burn coal?
2:43:48 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	May have question in post-hearing DR, attachment to spreadsheet. (Click on link for further comments.)
2:44:10 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Coal conservation adder strategy, Amos Units 1, 2, and 3, Mountaineer plant, Rockport 1 and 2, and Mitchell plants?
2:44:28 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	All vertically integrated utilities?
2:44:36 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Subject to jurisdiction of other states besides Kentucky?
2:44:48 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	What commission oversees Rockport 1 and 2?
2:45:07 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	If do review, be Michigan PSC and Indiana?
2:45:15 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Who owns Mountaineer plant?
2:45:24 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Subject to which?
2:45:41 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Amos 1, 2, and 3 owned by APCo as well?
2:45:46 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	So subject to West Virginia and Virginia and FERC?
2:45:50 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Where Wheeling fit in to all of this?
2:46:24 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Wheeling has 50 percent interest in Mitchell, have any other generation assets?
2:46:38 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Prior Wheeling and Kentucky Power purchasing Mitchell, who owned?

2:46:50 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	When deregulated, had to find buyer for generation?
2:47:05 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Other units using coal adder, any other commissions reviewed use coal conservation adder, found unreasonable, or disallowed any costs?
2:48:12 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Passing out for identification purposes order from PSC of West Virginia.
2:49:05 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Have copy of order?
2:49:10 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Assume familiar one of the witnesses?
2:49:25 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Pages 22 and 23, second full paragraph page 22, commission discussing Exhibit 4 and data requested, also include Wheeling Power?
2:50:23 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Familiar with post-hearing data response refer to, Exhibit 4?
2:50:32 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Know included information related to Mitchell units?
2:50:43 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Would Kentucky Power able provide response?
2:51:39 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Understood, and probably receive confidential treatment?
2:51:52 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Ask in post-hearing data request the request West Virginia made and response?
2:51:53 PM	POST-HEARING DATA REQUEST	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS VAUGHAN
	Note: Sacre, Candace	DATA REQUEST MADE BY WEST VIRGINIA PSC AND RESPONSE
2:52:15 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Scheduling discussion. (Click on link for further comments.)
2:52:50 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Recess.
2:52:54 PM	Session Paused	
3:08:07 PM	Session Resumed	
3:08:08 PM	Vice Chair Hatton	
	Note: Sacre, Candace	Back on record. Mr. Pinney?
3:08:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Purchases made for internal load and this is cost, would indicate Kentucky Power generating units not available?
3:08:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Cross Examination (cont'd). 2022-00263, Response, Staff First, Item 16, Attachment 5, Lines 6-15, how information filed with Commission, purchase allocated to internal load, purchases from PJM?
3:09:21 PM	Via Presentation Activated	
3:11:01 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Go to Net Gen, scroll over here, Big Sandy is offline for this period and Mitchell 1 and 2 in reserve shutdown?
3:11:56 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	For period of time discussing, accept Big Sandy in reserve shutdown, Mitchell 2 in maintenance outage, and Mitchell 1 in reserve shutdown, producing any power?

3:13:02 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	If three units offline, over here the input for power tracker, where power come from, where 75 come from?
3:13:55 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Examination. Is that a most likely from Rockport, need to confirm that?
3:14:24 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Confirm in post-hearing data request. (Click on link for further comments.)
3:14:51 PM	Via Presentation Deactivated	
3:15:24 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Cross Examination (cont'd). Are there instances when unit put in reserve shutdown other than when not clear day-ahead market?
3:16:47 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	When unit in reserve shutdown, is there difference in O&M costs or what has to be done than if dispatched?
3:17:25 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Direct, Rosenberger, 2023-00008, pages 4-9, planned and maintenance outages, why extended past anticipated length, documentation additional steps taken when outage went longer?
3:19:22 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Documentation available confirm additional steps taken beyond six-day work week?
3:19:37 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	May ask for post-hearing data request. (Click on link for further comments.)
3:19:50 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	During period under review, Kentucky Power extend any outages for preserving coal stockpile?
3:20:24 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	West Virginia order, mark as Exhibit 1, move into evidence. (Click on link for further comments.)
3:20:25 PM	PSC STAFF HEARING EXHIBIT 1	
	Note: Sacre, Candace	EXEC ATTY ADVISOR PINNEY - WITNESS KEARNS
	Note: Sacre, Candace	PSC OF WEST VIRGINIA CASE NO. 23-0377-E-ENEC ORDER
3:21:14 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Page 29 of order, first full paragraph, reading (click on link for further comments), when do Wheeling and Kentucky Power coordinate outages?
3:23:14 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Who comprised operating committee?
3:23:37 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Kentucky Power and Wheeling still sit on committee for operations?
3:23:53 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Majority of period of time, it was?
3:24:01 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Wheeling Power referred to in West Virginia PSC order?
3:24:20 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Know if West Virginia PSC referring to Mitchell units when it stated, reading (click on link for further comments)?
3:25:29 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Was that brackets were corroded that needed be replaced?
3:25:50 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	What mean if had coal classified as forced outage?

3:26:30 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Response, Staff First, 2023-00008, Item 14, Attachment 1, lists generating unit outages from May 1 2022 to Oct 31 2022, labeled as maintenance but reasons given are preplanned outage preparation, explain?
3:27:38 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Two instances?
3:27:47 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Big Sandy, one from Sept 8 to Sept 10 2022 and one for Mitchell 2 on Sept 3 through Sept 10 2022, preplanned outage prep work?
3:29:04 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Planned outages approved a year in advance by PJM?
3:29:16 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Preplanned outage prep work at Mitchell 2 leads into planned outage, parameters nine days?
3:29:23 PM	Exec Atty Advisor Pinney - witness Kearns and Rosenberger	
	Note: Sacre, Candace	Take extra time maintenance outage where not done before but shortened planned outage time?
3:30:41 PM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Same rationale for Big Sandy preplanned outage preparation?
3:32:16 PM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Not believe two explanations in previous cases 2022-00263 and 2022-00236, because market not soft or this newer approach or approach implemented before?
3:33:28 PM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	To get early start, declare maintenance outage or was in reserve shutdown?
3:34:17 PM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Know if adder strategy used put in reserve shutdown or it was just the bids?
3:34:34 PM	Exec Atty Advisor Pinney - witness Mell	
	Note: Sacre, Candace	Can request put in maintenance outage in that short period?
3:35:00 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Response, Staff First 2022-00263, attachment to Item 15, Massey and Rosenberger sponsoring witnesses, Mitchell 1 either outage or shutdown for 20 of those days?
3:36:57 PM	Exec Atty Advisor Pinney - witness Rosenberger and Kearns	
	Note: Sacre, Candace	Walk through (click on link for further comments), not see were online and generating for review period, only time operating Jan 10 to Jan 30?
3:40:15 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Some maintenance work could do and some in reserve shutdown can do?
3:40:50 PM	Exec Atty Advisor Pinney - witness Rosenberger	
	Note: Sacre, Candace	Feb and Mar 2022, Unit 1 in reserve shutdown, in shutdown because of adder or because failed to clear?
3:41:12 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Adder program still in effect, offline Nov 2022?
3:41:50 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Any Kentucky Power units during review period go into unplanned outage?
3:42:15 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	May ask response across two-year segments post-hearing. (Click on link for further comments.)

3:42:31 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Talked about change in management committee at Mitchell, Sept 1 2022 Wheeling Power took over?
3:42:50 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	As operator, have authority to determine maintenance practices and, when outages occur, still consult with Kentucky Power?
3:43:26 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Mitchell 1 now, Dec 19 last year, Mitchell suffer significant outage?
3:43:54 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	With that, what current status?
3:44:09 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	How that outage reported to PJM?
3:44:15 PM	Exec Atty Advisor Pinney - witness Kearns	
	Note: Sacre, Candace	Forced/unplanned, the same?
3:44:19 PM	Exec Atty Advisor Pinney	
	Note: Sacre, Candace	Would not have planned that one, I know that.
3:44:48 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Stegall Rebuttal, 2022-00263, refers coal supply issue across PJM fleet, average capacity factor 37 percent during review period, high PJM LMPs, accurate?
3:44:58 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	How capacity factor get calculated?
3:47:06 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	With information from PJM, distinguish for coal units whether owned by merchant operator or vertically integrated utility?
3:47:49 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Know percentage of PJM coal fleet comprised of AEP units?
3:48:48 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Customers paying for Mitchell plants, Kentucky Power customers and Wheeling customers paying for Mitchell coal plants to maintain?
3:50:23 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Discussion between you and Kurtz or you and West talking about PUE and use of that?
3:50:36 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Is PUE always bookmark used to determine what is an economic purchase and not economic purchase?
3:51:04 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Times when coal units or Big Sandy exceed PUE?
3:51:52 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	In determining cost to run for hour, have Mitchell runs for two hours, high cost of running, has to come down, exceeds PUE, use Mitchell as highest cost unit for hour?
3:52:50 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	The limiter?
3:53:00 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Said PUE not something no longer suitable for use in an RTO?
3:53:20 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	If not suitable, propose alternatives in recent rate cases or not seek changes how economic purchases made or calculated?
3:54:04 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	If not suitable, propose alternatives in most recent rate case or not seek changes how economic purchases made?

3:55:24 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Presuming economic purchase for fuel adjustment cost purchase purposes an economic dispatch, economic in both means same thing?
3:55:47 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Economic dispatch and economic purchase, economic same thing?
3:57:24 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Generating resources be owned by investor-owned vertically integrated investor-owned utilities, Duke Kentucky for example, or also be merchant units?
3:57:53 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	When PJM making economic decisions to dispatch, is PJM agnostic to type of units?
3:58:34 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Be your testimony any purchase through PJM be economic purchase for FAC and able be recovered?
3:59:35 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Use of PUE is limiter not think fits into RTO, or just any limiter whatsoever?
4:00:02 PM	Exec Atty Advisor Pinney - witness Vaughan	
	Note: Sacre, Candace	Said PUE not appropriate for use in RTO, any limiter inappropriate, different result if Kentucky Power had CT, opinion change how calculate?
4:01:57 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Examination. Rebuttal, page 6, table comparing Mitchell net capacity to PJM coal fleet net capacity factor, make statement line 4, reading (click on link for further comments), similar to Mitchell plants?
4:02:43 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Mitchell performs as well as PJM other coal units over 10-year average, what take from this table?
4:03:29 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Same table, five-year average, if look at last five years, only 2019 Mitchell have exceeded PJM fleet in net capacity factor?
4:03:55 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Willing agree over past five years PJM coal fleet net capacity factor average 38.66 and Mitchell 32.82 below?
4:04:52 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	If think 10-year average significant and useful, then five-year average also significant for same reasons?
4:05:12 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Examination. Discussions things get volatile, stockpile some coal?
4:07:28 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Discussed but discarded as an idea, decided not need to?
4:07:51 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Anyone else here was involved in discussions?
4:09:49 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Looking-back period, critically low stockpiles of coal, what could have been done differently?
4:11:58 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	In retrospect, not have done anything differently?
4:12:34 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	RFP process changed, become more flexible?
4:13:04 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Done in week instead of month?

4:13:12 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	As read testimony, long-term contracts mostly fulfilled, short-term contracts spot market coal purchases problem?
4:13:29 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Not any litigation?
4:13:34 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Only one force majeure?
4:13:44 PM	Vice Chairman Hatton - witness Chilcote	
	Note: Sacre, Candace	Change evaluation long-term coal need to purchase, mix of short- and long-term been different?
4:14:53 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Company position fairly stable since 2008, testimony says, reading (click on link for further comments), knowing expected to be uncertain and realizing happen since COVID, customers paying, critical stockpile shortage, what be done lessen impact?
4:18:30 PM	Vice Chairman Hatton - witness Vaughan	
	Note: Sacre, Candace	Have to talk about failure to generate power opposed to purchasing in RTO?
4:19:08 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Redirect?
4:19:15 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Redirect Examination. Remember talking about peaking unit equivalent with Kurtz, provided KIUC 1, still have that?
4:19:34 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Questions whether clear start-up costs applied each hour of PUE calculation?
4:19:58 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	PUE calculation always hourly calculation?
4:20:03 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Described how cost of peaking unit equivalent calculated beginning line 3?
4:20:12 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	On page 33?
4:20:17 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Line 9, says, reading (click on link for further comments, correct?
4:20:33 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Identifying it was an hourly calculation?
4:20:38 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Footnote 10 describes peaking unit calculation as hourly calculation?
4:20:44 PM	Atty Gish Kentucky Power	
	Note: Sacre, Candace	Handing out exhibit, printout Kentucky Power Response to Staff 1-73, Attachment 78, workpaper for Exhibit AEV-8.
4:21:24 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Mark as Kentucky Power 1? (Click on link for further comments.)
4:21:25 PM	KENTUCKY POWER HEARING EXHIBIT 1	
	Note: Sacre, Candace	ATTY GISH KENTUCKY POWER - WITNESS VAUGHAN
	Note: Sacre, Candace	KENTUCKY POWER RESPONSE, STAFF 1-73, ATTACHMENT 78, WORKPAPER FOR EXHIBIT AEV-8
4:21:35 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Says proposed new peaking unit equivalent cost calculation, identified an hourly calculation?
4:21:53 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Is daily gas price times heat rate plus total dollars-per-megawatt adjustment?

4:22:02 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	And total dollar-per-megawatt-hour adjustment includes startup costs?
4:22:12 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Startup costs added to hourly calculation of peaking unit equivalent disclosed to Commission?
4:22:35 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Question this morning about Ceredo, third page of exhibit summary of costs from Ceredo unit, see?
4:22:57 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Why use Ceredo unit?
4:23:14 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	If told Commission want to add $30 startup cost with no support, would have approved that?
4:23:28 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Says Ceredo 1 right on document?
4:23:32 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Filed with application?
4:23:37 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Familiar with West Virginia ENC cost denial, correct?
4:23:55 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Mentioned earlier Appalachian Power regulated by three utility regulatory entities?
4:24:14 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Public Service Commission of West Virginia only entity opined on program in this manner?
4:26:23 PM	Atty Gish Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Provided testimony about fuel prices during review period, average fuels prices during second half 2022?
4:26:56 PM	Atty Gish Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Current gas price?
4:27:07 PM	Atty Gish Kentucky Power - witness Stutler	
	Note: Sacre, Candace	Prices during 2022 four times higher than today?
4:27:16 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	What were prices for coal that was available 2022?
4:28:11 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	AEP file litigation against coal suppliers during time period?
4:29:00 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	Kentucky Power have to file coal supply litigation?
4:29:10 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	Because not need to?
4:29:17 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	What is current price of coal?
4:29:35 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	Issue getting coal from mine during constraint, why supplier not able provide all coal want?
4:31:00 PM	Atty Gish Kentucky Power - witness Vaughan	
	Note: Sacre, Candace	Remember Kurtz talking ability company recover fuel costs through base rates, remember?
4:31:12 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	Last base rate case had a test year Mar '22 to Mar '23?
4:31:24 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	Period of highest fuel costs seen in decades?

4:31:33 PM	Atty Gish Kentucky Power - witness Chilcote	
	Note: Sacre, Candace	If included fuel costs in base rates, customers pay high fuel costs regardless fuel costs was?
4:32:30 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Recross?
4:32:46 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Call Randy Futral.
4:32:59 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Witness is sworn.
4:33:10 PM	Atty Kurtz KIUC - witness Futral	
	Note: Sacre, Candace	Direct Examination. File direct testimony in Case No. 2022-00263 and 2023-00008?
4:33:25 PM	Atty Kurtz KIUC - witness Futral	
	Note: Sacre, Candace	Changes?
4:34:00 PM	Atty Kurtz KIUC - witness Futral	
	Note: Sacre, Candace	Change substance of testimony?
4:34:05 PM	Atty Kurtz KIUC - witness Futral	
	Note: Sacre, Candace	If ask same questions, answers be same?
4:34:14 PM	Vice Chairman Chandler	
	Note: Sacre, Candace	Questions?
4:34:47 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Lane Kollen.
4:34:57 PM	Atty Gish Kentucky Power	
	Note: Sacre, Candace	Move to enter company Exhibit 1. (Click on link for further comments.)
4:34:58 PM	KENTUCKY POWER HEARING EXHIBIT 1	
	Note: Sacre, Candace	ATTY GISH KENTUCKY POWER - WITNESS VAUGHAN
	Note: Sacre, Candace	KENTUCKY POWER RESPONSE, STAFF 1-73, ATTACHMENT 78, WORKPAPER FOR EXHIBIT AEV-8
4:35:10 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Witness is sworn.
4:35:22 PM	Atty Kurtz KIUC - witness Kollen	
	Note: Sacre, Candace	Direct Examination. Provide direct testimony in Case No. 2022-00263 and 2023-00008?
4:35:33 PM	Atty Kurtz KIUC - witness Kollen	
	Note: Sacre, Candace	Corrections?
4:35:40 PM	Vice Chairman Chandler	
	Note: Sacre, Candace	Ms. Glass or Mr. Gish?
4:35:43 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Cross Examination. Been employed as operator of coal-fired power plant?
4:36:00 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been employed as operator of natural gas-fired power plan?
4:36:05 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been employed as buyer of purchased power?
4:36:28 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been employed as buyer of coal?
4:36:34 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been employed as buyer of natural gas?
4:36:42 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been employed as engineer?
4:36:48 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Have engineering degrees?

4:36:54 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Been licensed as an engineer?
4:36:59 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Recommend Commission disallow certain costs recovered through fuel adjustment clause over review period?
4:37:10 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Futral also recommends Commission disallow costs recovered through fuel adjustment clause over review period?
4:37:20 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Amount recommend commission disallow include amounts for disallowance by Futral?
4:37:33 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Total amount recommended to be disallowed by AG/KIUC in this case?
4:37:49 PM	Atty Kurtz KIUC	
	Note: Sacre, Candace	Hand Kollen testimony. (Click on link for further comments.)
4:38:56 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Direct you to page 17 Futral testimony, starting on line 1, and he says, reading (click on link for further comments)?
4:39:14 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Sentence implies cumulative amount between you and Futral?
4:39:22 PM	Atty Glass Kentucky Power - witness Kollen	
	Note: Sacre, Candace	Total amount recommended be disallowed by AG/KIUC $59.7 million for 100-megawatt PUE?
4:39:39 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Questions?
4:39:58 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Outstanding motions. (Click on link for further comments.)
4:40:04 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Admission of exhibits. (Click on link for further comments.)
4:40:20 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Post-hearing data requests. (Click on link for further comments.)
4:40:37 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Anything else? (Click on link for further comments.)
4:40:39 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Briefing schedule. (Click on link for further comments.)
4:41:15 PM	Vice Chairman Hatton	
	Note: Sacre, Candace	Hearing adjourned.
4:41:30 PM	Session Ended	

Exhibit List Report

2023-00008 13Feb2023

Kentucky Power Company (Kentucky Power)

Name:	Description:
ATTY GENERAL HEARING EXHIBIT 1	COMMISSION ORDER 2017-00179 JAN 18 2018
KENTUCKY POWER HEARING EXHIBIT 1	KENTUCKY POWER RESPONSE, STAFF 1-73, ATTACHMENT 78, WORKPAPER FOR EXHIBIT AEV-8
KIUC HEARING EXHIBIT 1	VAUGHAN TESTIMONY FROM 2017 CASE
KIUC HEARING EXHIBIT 2	KENTUCKY POWER 2022-00036 RESPONSE STAFF POST-HEARING DATA REQUEST AUG 8 2022 WITNESS: STEGALL
KIUC HEARING EXHIBIT 3	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 ITEM 3 ATTACHMENT 6 TAB 1 OF 7: 10-2022
KIUC HEARING EXHIBIT 4	2023-00008 KIUC FIRST SET OF DATA REQUESTS OCT 26 2023 ITEM 3 ATTACHMENT 2 TAB 1 OF 7: 6-2022
KIUC HEARING EXHIBIT 5	TITLE 807 CHAPTER 005 REGULATION 056
PSC STAFF HEARING EXHIBIT 1	PSC OF WEST VIRGINIA CASE NO. 23-0377-E-ENEC ORDER

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC APPLICATION OF KENTUCKY POWER COMPANY FOR (1) A GENERAL ADJUSTMENT OF ITS RATES FOR ELECTRIC SERVICE; (2) AN ORDER APPROVING ITS 2017 ENVIRONMENTAL COMPLIANCE PLAN; (3) AN ORDER APPROVING ITS TARIFFS AND RIDERS; (4) AN ORDER APPROVING ACCOUNTING PRACTICES TO ESTABLISH REGULATORY ASSETS AND LIABILITIES; AND (5) AN ORDER GRANTING ALL OTHER REQUIRED APPROVALS AND RELIEF	)))))))))))	CASE NO. 2017-00179

ORDER

Kentucky Power Company ("Kentucky Power"), a wholly owned subsidiary of American Electric Power Company, Inc. ("AEP") is an electric utility that generates, transmits, distributes, and sells electricity to approximately 168,000 consumers in all or portions of 20 counties in eastern Kentucky.[1] Kentucky Power owns and operates a 285-megawatt ("MW") gas-fired steam-electric generating unit in Louisa, Kentucky, and owns and operates a 50 percent undivided interest in a coal-fired generating station in Moundsville, West Virginia; Kentucky Power's share consists of 780 MW. Kentucky Power obtains an additional 393 MW from Rockport (Indiana) Plant Generating Units No. 1 and No. 2 under a unit power agreement ("Rockport UPA"). Kentucky Power's transmission system is operated by PJM Interconnection, LLC ("PJM"), a regional

[1] Application at 2. Kentucky Power also furnishes electric service at wholesale to the Cities of Olive Hill and Vanceburg, Kentucky.

ATTY GENERAL HEARING EXHIBIT 1

electric grid and market operator. Kentucky Power's most recent general rate increase was granted in June 2015 in Case No. 2014-00396.[2]

BACKGROUND

On April 26, 2017, Kentucky Power filed notice of its intent to file an Application ("Application") for approval of an increase in its electric rates based on a historical test year ending February 28, 2017. By Order entered May 24, 2017, the Commission granted Kentucky Power's motion to deviate from certain filing requirements, which Kentucky Power requested in order to obtain additional time to review its Application before its proposed filing date of June 28, 2017.

Kentucky Power tendered its Application on June 28, 2017, which included new rates to be effective on or after July 29, 2017, based on a request to increase its electric revenues by $65,387,987, or 11.80 percent. On August 7, 2017, Kentucky Power supplemented its Application to reflect the impact of refinancing of certain debts in June 2017, which reduced Kentucky Power's requested annual increase in revenues to $60,397,438. In its Application, Kentucky Power also requested approval of its environmental compliance plan, and proposed to revise, add, and delete various tariffs applicable to its electric service. After Kentucky Power cured filing deficiencies, its Application was deemed filed as of July 20, 2017. To determine the reasonableness of these requests, the Commission suspended the proposed rates for five months from their effective date, pursuant to KRS 278.190(2), up to and including January 18, 2018.

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[2] Case No. 2014-00396, *Application of Kentucky Power Company for: (1) A General Adjustment of Its Rates for Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs and Riders; and (4) An Order Granting All Other Required Approvals and Relief* (Ky. PSC June 22, 2015) ("Case No. 2014-00396, Final Order").

The following parties requested and were granted full intervention: the Attorney General of the Commonwealth of Kentucky, by and through his Office of Rate Intervention ("Attorney General"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Kentucky Commercial Utility Customers, Inc. ("KCUC"); Kentucky Cable Telecommunications Association ("KCTA"); and Wal-Mart Stores East, LP and Sam's East, Inc. (jointly, "Walmart").

By order entered on July 17, 2017, the Commission established a procedural schedule that provided for discovery, intervenor testimony, rebuttal testimony from Kentucky Power,[3] a formal evidentiary hearing, and an opportunity for the parties to file post hearing briefs.[4] On October 26, 2017, and November 7, 2017, an informal conference ("IC") was held at the Commission's offices to discuss procedural matters and the possible resolution of pending issues. All parties participated in the IC held on October 26, 2017, with the exception of KCTA, who engaged in separate discussions with Kentucky Power regarding possible resolution of issues pertaining to the Cable Television Pole Attachment Tariff ("Tariff C.A.T.V.") The Attorney General did not attend the November 7, 2017 IC due to a scheduling conflict, but indicated that the IC should proceed as scheduled. At the November 7, 2017 IC, the parties in attendance,

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[3] On October 11, 2017, the Attorney General filed a motion to amend the procedural schedule to permit him to file rebuttal testimony. Kentucky Power and KLC each filed responses in opposition. By order issued October 24, 2017, the Commission found the Attorney General failed to establish good cause to amend the procedural schedule and denied the Attorney General's motion.

[4] The Commission conducted public meetings in Kentucky Power's service territory on November 2, 2017, in Prestonsburg, Kentucky; on November 6, 2017, in Hazard, Kentucky; and on November 8, 2017, in Ashland, Kentucky.

with the exception of KCUC, arrived at an agreement in principle for the resolution of the issues raised in this case.

On November 22, 2017, Kentucky Power, KIUC, KLC, KSBA, KCTA, and Walmart ("Settling Intervenors") filed a Settlement Agreement ("Settlement") that addressed all of the issues raised in this proceeding. The Attorney General and KCUC are not signatories to the Settlement. The Settlement is attached as Appendix A to this Order.

Because the Settlement was not unanimous, the December 6, 2017, evidentiary hearing was held as scheduled for the purposes of hearing testimony in support of the Settlement and on contested issues. On January 5, 2018, Kentucky Power, the Attorney General, KIUC, and KCUC filed their respective post hearing briefs. The matter now stands submitted to the Commission for a decision.

SETTLEMENT AGREEMENT

The Settlement reflects the agreement of the parties, except for the Attorney General and KCUC, on all issues raised in this case. The major substantive areas addressed in the Settlement are as follow:

- Kentucky Power's electric retail revenues should be increased by $31,780,734, effective January 19, 2018.[5] This amount consists of a base rate revenue reduction of $28,616,704 from the $60,397,438 requested in Kentucky Power's August 7, 2017 supplemental filing.

[5] Settlement, paragraphs 2(a) and 17.

- Establishment of deferral mechanisms for \$50 million in non-fuel, non-environmental Rockport UPA expenses.[6]

- Amendment of the Purchase Power Adjustment tariff ("Tariff P.P.A.") to recover incremental PJM Open Access Transmission Tariff ("OATT") Load Serving Entity ("LSE") charges and credits above or below net PJM OATT LSE charges and credits in base rates.[7]

- Amendment of Tariff P.P.A. as described in the Direct Testimony of Alex E. Vaughan ("Vaughan Direct Testimony") to collect from, or credit to, customers the amount of purchased power costs that are excluded from recovery through the Fuel Adjustment Clause ("FAC"), and gains and losses from incidental sales of natural gas purchased for use at Big Sandy Unit 1, but not used or stored.[8]

- Establishment of 20-year service life for Big Sandy Unit 1 for depreciation rates.[9]

- Establishment of a return on equity of 9.75 percent.[10]

- Agreement to lower the Kentucky Economic Development Surcharge rate ("Tariff K.E.D.S.") for residential customers and increase the rate for non-residential customers, with matching contribution by Kentucky Power.[11]

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[6] *Id.* at paragraph 3.

[7] *Id.* at paragraph 4.

[8] *Id.* at paragraph 6.

[9] *Id.* at paragraph 7.

[10] *Id.* at paragraph 8.

[11] *Id.* at paragraph 10.

- Agreement to continue Tariff K-12 School as a permanent customer class instead of a pilot rate.[12]

- Agreement that Kentucky Power will not request a general adjustment of base rates for rates that would be effective prior to the January 2021 billing cycle.[13]

- Increase Kentucky Power's customer charge for Residential Service customers to $14.00 per month.[14]

CONTESTED REVENUE REQUIREMENT AND REVENUE ALLOCATION ISSUES

Kentucky Power proposed an annual increase in its electric revenues of $60,397,438 in its August 7, 2017 supplemental filing. Through testimony, the Attorney General contended that Kentucky Power should be allowed to increase its electric revenues by $39.9 million.[15] Through testimony, KCUC contended that the revenue allocation contained in the Settlement does not provide fair or reasonable treatment for customers in the Large General Service class ("Tariff L.G.S."). Because the parties have not reached a unanimous settlement on the increase in revenues, the Commission must consider the evidentiary record on these issues as presented by Kentucky Power, the Attorney General, and KCUC, and render a decision based on a determination of Kentucky Power's capital, rate base, operating revenues, operating expenses, and revenue allocation, as would be done in a fully litigated rate case

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[12] *Id.* at paragraphs 1213.

[13] *Id.* at paragraph 5.

[14] *Id.* at paragraph 16.

[15] Direct Testimony of Ralph C. Smith ("Smith Testimony") at 12.

TEST PERIOD

Kentucky Power proposed the 12-month period ending February 28, 2017, as the test period for determining the reasonableness of its proposed rates. None of the Intervenors contested the use of this period as the test period. The Commission finds it is reasonable to use the 12-month period ending February 28, 2017, as the test period in this case. Due to the timing of Kentucky Power's filing, the 12-month period ending February 28, 2017, is the most recent feasible period to use for setting rates and, except for the adjustments approved herein, the revenues and expenses incurred during that period are neither unusual nor extraordinary.[16] In using this historic test period, the Commission has given full consideration to appropriate known and measurable changes.

RATE BASE

Jurisdictional Rate Base Ratio

Kentucky Power proposed a test-year-end Kentucky jurisdictional rate base of $1,323,494,246.[17] The Kentucky jurisdictional rate base is divided by Kentucky Power's test-year-end total company rate base to derive the Kentucky jurisdictional rate base ratio ("jurisdictional ratio"). This jurisdictional ratio is then applied to Kentucky Power's total company capitalization to derive the Kentucky jurisdictional capitalization. The jurisdictional ratio uses the test-year-end rate base before any ratemaking adjustments

[16] On May 22, 2017, Kentucky Power filed a motion to deviate from filing requirement 807 KAR 5:001, Section 12(1)(a), which requires the submission of a detailed financial exhibit for the 12-month test period ending not more than 90 days prior to the date of its application. Kentucky Power requested to deviate by filing the required financial exhibit for 12-month period ending 120 days, rather than 90 days, prior to the date of its application. By Order, the Commission approved Kentucky Power's motion to deviate from 807 KAR 5:001, Section 12(1)(a) (Ky. PSC May 24, 2017).

[17] Application, Section V, Exhibit 1, Schedule 4.

applicable to either Kentucky jurisdictional operations or other jurisdictional operations. Kentucky Power used a jurisdictional ratio of 98.3 percent.[18] The Commission finds the calculation of Kentucky Power's test-year electric rate base reasonable for purposes of establishing the jurisdictional ratio.

Pro Forma Jurisdictional Rate Base

Kentucky Power calculated a pro forma jurisdictional rate base of $1,194,888,447,[19] which reflects the types of adjustments made by the Commission in prior rate cases to determine the pro forma rate base.

The Attorney General proposed one adjustment to Kentucky Power's proposed rate base for the Cash Working Capital ("CWC") allowance. The Attorney General proposed an allowance of $18,953,980, which is $740,459 lower than the $19,694,529 proposed by Kentucky Power in its Application. While indicating a preference for using a lead-lag study, the Attorney General stated that if CWC is to be calculated using the Commission's long-standing 1/8th formula approach, then the proper level of CWC for ratemaking purposes should be based on the pro forma operations and maintenance expenses allowed by the Commission.[20] The Attorney General also stated that since Kentucky Power's revenue requirement is calculated based upon its jurisdictional capitalization rather than its adjusted jurisdictional rate base, any adjustment to CWC would have no impact on the revenue requirement.[21]

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[18] *Id.* The non-jurisdictional percentage of approximately 1.7 percent is due to the furnishing of electric service at wholesale to the City of Olive Hill and the City of Vanceburg.

[19] *Id.*

[20] Smith Testimony at 22.

[21] *Id.* at 23.

While the Commission agrees with the methodology the Attorney General utilized for calculating the CWC, the Commission does not agree with the Attorney General's proposed CWC. The CWC allowance included in the rate base, as shown below, is based on the adjusted operation and maintenance ("O&M") expenses discussed in this Order, as approved by the Commission. The Commission has determined Kentucky Power's pro forma jurisdictional rate base for ratemaking purposes for the test year to be as follows:

Total Utility Plant in Service	$2,264,648,845
Add:	
Materials & Supplies	36,344,575
Prepayments	49,905,719
Cash Working Capital Allowance	18,905,292
Subtotal	$105,155,586
Deduct:	
Accumulated Depreciation	764,544,392
Customer Advances	27,076,876
Accumulated Deferred Income Taxes	384,084,108
Contributions in Aid of Construction	
Subtotal	$1,175,705,376
Pro Forma Rate Base	$1,194,099,055

Reproduction Cost Rate Base

KRS 278.290 (1) states, in relevant part, that:

> [T]he commission shall give due consideration to the history and development of the utility and its property, original cost, cost of reproduction as a going concern, capital structure, and other elements of value recognized by the law of the land for ratemaking purposes.

Neither Kentucky Power, the Attorney General, nor KCUC provided information regarding Kentucky Power's proposed Kentucky jurisdictional reproduction cost rate base. Therefore, the Commission finds that using Kentucky Power's historic costs for deriving its rate base is appropriate and consistent with Commission precedent involving Kentucky Power, as well as other Kentucky jurisdictional utilities.

CAPITALIZATION

Kentucky Power proposed an adjusted Kentucky jurisdictional capitalization of $1,191,785,493.[22] This amount was derived through adjustments to exclude certain environmental compliance investments that remain part of the environmental rate base and are included in Kentucky Power's environmental surcharge mechanism.

Kentucky Power determined its electric capitalization by multiplying its total company capitalization by the rate base jurisdictional allocation ratio described earlier in this Order. This is consistent with the approach used in previous Kentucky Power rate cases.

The Attorney General did not recommend any adjustments to Kentucky Power's capitalization. The Attorney General proposed one adjustment to rate base for CWC, since it does not affect Kentucky Power's jurisdictional capitalization, but recommended no change to the amount proposed by Kentucky Power.

The Commission finds the proposed amount of Kentucky Power's jurisdictional capitalization is reasonable.

REVENUES AND EXPENSES

For the test year, Kentucky Power reported actual net operating income from its electric operations of $85,033,742.[23] Kentucky Power proposed 55 adjustments to

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[22] Application, Section II, Exhibit L.

[23] Application, Section V, Exhibit 1, Supplemental Schedule 4 (filed Aug. 7, 2017).

revenues and expenses to reflect more current and anticipated operating conditions, resulting in an adjusted net operating income of $43,690,670.[24] With this level of net operating income, Kentucky Power reported an adjusted test year revenue deficiency of $60,397,438.[25]

The Attorney General accepted 45 of Kentucky Power's proposed adjustments to its test-year revenues and expenses.

A list of the non-contested adjustments is contained in Appendix B to this Order. The Attorney General proposed 14 additional adjustments to Kentucky Power's operating income relating to: 1) theft recovery revenue; 2) payroll expense – employee merit increase; 3) overtime payroll expense related to employee merit increase; 4) payroll tax expense; 5) incentive compensation expense; 6) stock-based compensation; 7) savings plan expense; 8) supplemental executive retirement program expense; 9) affiliate charge for corporate aviation expense; 10) storm damage expense; 11) relocation expense; 12) gain on sale of utility property; 13) cash surrender value of life insurance policies; and 14) rate case expense.

The Attorney General's proposed adjustments pertain solely to Kentucky Power's base rate revenue requirements. The Commission makes the following determinations regarding the Attorney General's proposed base rate adjustments.

<u>Theft Recovery Revenue</u>

The Attorney General proposed an adjustment to increase Kentucky Power's theft recovery revenue by $166,698 based upon Kentucky Power's estimate of

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[24] *Id.*

[25] *Id.* at Schedule V, Supplemental Exhibit 2 (filed Aug. 7, 2017).

increased theft recovery revenue.[26] Kentucky Power expects to increase theft recovery revenue due to the addition of a new administrative assistant who would allow Kentucky Power's field investigators to spend more time on suspected energy theft.

The Commission finds that the Attorney General's proposed adjustment regarding theft recovery revenue is reasonable, and therefore the proposed adjustment for theft recovery revenue of $166,698 should be allowed for ratemaking purposes.

Payroll Expenses: Employee Merit Increase, Overtime Payroll Expense, and Payroll Taxes

The Attorney General proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increases, and associated payroll taxes in the amount of $57,205, $4,148, and $48,362, respectively. The Attorney General argued that Kentucky Power did not justify basing its proposed payroll expense adjustment on an annual merit increase of 3.5 percent. The Attorney General maintained that the payroll expense adjustment should be based upon a 3.0 percent merit increase.[27] Limiting the merit increase to 3.0 percent results in corresponding adjustments to overtime and payroll tax expenses. The payroll tax adjustment includes the impact of limiting the merit increase to 3.0 percent and other adjustments to incentive compensation and stock-based compensation proposed by the Attorney General.

Kentucky Power maintained that the test year wage increases are reasonable. A comparison of Kentucky Power's total target compensation with the 2016 EAPDIS

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[26] Smith Testimony at 24; Kentucky Power's Response to the Attorney General's First Request for Information ("Attorney General's First Request"), Item 319.

[27] *Id.* at 26-30.

Energy, Technical, Craft & Clerical Survey (Southeast region data) reveals that, on average, Kentucky Power's compensation was 5.4 percent below the average for the region.[28] Kentucky Power claimed that, in light of the survey results, the test year wage increases were necessary to provide market competitive wages to target and retain employees.

The Commission finds that Kentucky Power's test year wages are reasonable and that the Attorney General's proposed adjustments to payroll expense for employee merit increases for non-exempt salaried employees, overtime payroll expense related to employee merit increase and payroll taxes should be denied.

Incentive Compensation and Stock Based Compensation

Kentucky Power included $3,900,806 of incentive compensation plan ("ICP") costs[29] and $1,758,874 in Long-Term Incentive Plan ("LTIP") costs in its Kentucky jurisdictional revenue requirement.[30] These amounts reflect the adjustments made by Kentucky Power.[31] In the Settlement, Kentucky Power and the Settling Intervenors agreed to reduce incentive compensation expenses by $3.15 million, which included incentive compensation and stock-based compensation.

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[28] Application, Direct Testimony of Andrew J. Carlin ("Carlin Direct Testimony"), Exhibit ARC-4.

[29] Kentucky Power's Response to Commission Staff's Second Request for Information (Staff's Second Request"), Item 85; Kentucky Power's Response to KIUC's First Request for Information ("KIUC's First Request"), Item 31.

[30] Smith Testimony at 31. This consists of Kentucky Power direct-charged jurisdictional O&M expense of $2,255,760, AEP allocated amount of $3,118,781 and charges from other affiliates of $51,300 less $1,525,035 that was removed from the revenue requirement per the Application, Section V, Exhibit 2, Workpaper 32.

[31] Application, Direct Testimony of Tyler H. Ross ("Ross Direct Testimony") at 14.

The Attorney General recommended reducing incentive compensation expense by a total of $3,096,868. The Attorney General recommended an adjustment of ICP costs that decreased test year expense by $1,350,120 on a Kentucky jurisdictional basis, which represented the removal of the 25 percent of ICP costs that represent performance measures tied to increasing shareholder value.[32] The Attorney General maintained that ratepayers should not be responsible for those costs because Kentucky Power's shareholders are the main beneficiaries of the 25 percent performance measure for quantitative financial objectives, which include earnings per share.[33] Similarly, the Attorney General argued that $1,746,748 in stock-based compensation costs should be removed because ratepayers should not be required to pay management compensation based on the performance of Kentucky Power's stock price, which primarily benefits Kentucky Power's parent company.[34] In support of his argument, the Attorney General pointed to previous cases in which the Commission held that ratepayers should not bear the cost of stock-based compensation programs unless there is clear and definitive quantitative evidence demonstrating a benefit to ratepayers.[35]

In response, Kentucky Power argued that the Attorney General's adjustment to the proposed incentive compensation expense was not warranted because the

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[32] Smith Testimony at 35, Exhibit RCS-1, page 3 of 32; Smith Testimony at 30-31. The 2016 ICP was weighted 75 percent to AEP's earnings per share and 25 percent to other metrics

[33] *Id.* at 31.

[34] *Id.* at 39.

[35] Case No. 2014-00397, Final Order at 27-28; Case No. 2005-00042, *An Adjustment of the Gas Rates of the Union Light, Heat and Power Company* (Ky. PSC Feb. 2, 2006); Case No. 2010-00036, *Application of Kentucky-American Water Company for an Adjustment of Rates Supported by a Fully Forecasted Test Year* (Ky. PSC Dec. 14, 2010).

incentive compensation programs provide benefits to both Kentucky Power's customers and its shareholders.[36]

The Commission finds that the Settlement provision that reduces incentive compensation by $3.15 million, which is a greater reduction than the adjustment recommended by the Attorney General, is reasonable and should be approved.

Savings Plan Expense

Kentucky Power included $1,662,975 in its jurisdictional revenue requirement for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.[37]

The Attorney General proposed a Kentucky jurisdictional adjustment of $1,102,496 for savings plan expense for employees who participate in a defined benefit plan and have matching 401(k) contributions from Kentucky Power.

In rebuttal, Kentucky Power explained that participation in the defined benefit plan ended in 2000 and benefits were frozen in 2010.[38] Therefore, Kentucky Power does not contribute to a defined benefit plan and 401(k) matching plan at the same time. The Commission has disallowed such matching contributions when both a defined benefit plan and 401(k) matching contribution exist concurrently. This is not the case with Kentucky Power.

The Commission finds that Kentucky Power's savings plan expense is reasonable and should be allowed for ratemaking purposes.

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[36] Rebuttal Testimony of Andrew R. Carlin ("Carlin Rebuttal Testimony") at 7.

[37] Kentucky Power's Response to Staff's Second Request, Item 56.h. and i.

[38] Dec. 7, 2017 H.V.T. at 4:50:20.

Supplemental Executive Retirement Plan ("SERP")

The Attorney General proposed an adjustment of $52,453 for the expense associated with Kentucky Power's Supplemental Executive Retirement Plan ("SERP"). The Attorney General argued that such plans provide benefits to executives that exceed amounts limited in qualified retirement plans by the Internal Revenue Service.[39] The Attorney General also maintained that the provision of additional retirement compensation to Kentucky Power's highest paid executives is not a reasonable expense that should be recovered in rates.

In rebuttal, Kentucky Power stated that the total benefit it provides under both its qualified and non-qualified plan is equal to the benefit that would be produced by the formulas utilized under the qualified plans if these plans were not subject to the benefit limitations imposed on qualified plans.[40]

The Commission finds the SERP expenses reasonable and, therefore, should be allowed for ratemaking purposes.

Affiliate Charge for Corporate Aviation Expense

The Attorney General proposed an adjustment of $382,769 to remove the cost of the AEP corporate aviation expense charged to Kentucky Power during the test year.[41] The Attorney General argued that AEP corporate aviation is a perquisite for AEP executives and directors and, as such, shareholders should bear the cost, not ratepayers.

[39] Smith Testimony at 42.

[40] Carlin Rebuttal Testimony at R-32.

[41] Smith Testimony at 43-44.

The Commission disagrees with the Attorney General's proposed adjustment for corporate aviation expense. While private jet travel may appear to be an extravagance, legitimate travel expenses would have been incurred through commercial airlines. The Commissions finds that the aviation expense proposed by Kentucky Power is reasonable and should be approved.

Storm Damage Expense

Kentucky Power proposed an adjustment of $595,932 for storm damage expense based upon a three-year average of major storm expense. The Attorney General proposed an adjustment to reduce storm damage expense by $595,932, arguing that Kentucky Power had not demonstrated a compelling reason to increase test year storm damage expense.[42]

Kentucky Power explained that it used a three-year average to normalize the level of costs to address the uncertainty regarding when, and how much, a major storm will affect Kentucky Power and because using only the test year amount in a base rate filing could lead to major swings in adjustments for storm damage expense.[43]

The Commission finds that Kentucky Power's storm damage expense adjustment is reasonable and should be allowed for ratemaking purposes.

Test Year Relocation Expense

Kentucky Power included a $318,073 adjustment for relocation expense in its test year revenue requirement.[44] The Attorney General proposed an adjustment to

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[42] *Id.* at 44.

[43] Rebuttal Testimony of Ranie K. Wohnhas ("Wohnhas Rebuttal Testimony") at R-18 – R-19.

[44] Kentucky Power's Response to the Attorney General's First Request, Item 251.

normalize relocation expenses that reduced the test year operating expenses by $140,972 on a Kentucky jurisdictional basis.[45]

In response to Commission Staff's Post-Hearing Data Request, Item 14, Kentucky Power stated that its relocation expense for the eight-month period March 1, 2017 to October 31, 2017 totaled $125,736. Annualized over a twelve-month period ending February 28, 2018, relocation expenses are forecasted to total $188,604. On a Kentucky jurisdictional basis, relocation expenses for the twelve months ending February 28, 2018 amount to $185,964.

The Commission finds that the relocation expense should be adjusted based upon the Kentucky jurisdictional relocation expenses for the twelve months ending February 28, 2018. This results in a decrease to the Kentucky jurisdictional relocation expense of $132,109.

<u>Gain on Sale of Utility Property</u>

The Attorney General proposed an adjustment to amortize a $996,669 gain on the sale of utility property ("Carrs Site") over three years for $327,240 per year on a Kentucky jurisdictional basis.[46] The Attorney General maintained that the Kentucky jurisdictional gain on the sale of utility property should flow back to customers.

In rebuttal, Kentucky Power argued that the gain on the sale of the property should not be adjusted to reduce its revenue requirement because the Carrs Site had not been included in rate base, and thus Kentucky Power had not received a return on

[45] Smith Testimony at 46.

[46] *Id.* at 47.

the Carrs Site for the last 33 years.[47] Kentucky Power also noted that it removed $60,539 in property taxes from its cost of service in this case.[48]

The Commission finds that, since Kentucky Power has not received a return on this investment and has excluded the property taxes from its cost of service, the proposed adjustment by the Attorney General is not reasonable and should be denied.

<u>Cash Surrender Value of Life Insurance</u>

Kentucky Power recorded expense in the test year associated with the cash surrender value of life insurance of former executives in a Kentucky jurisdictional amount of $26,941.[49]

The Attorney General asserted that Kentucky Power's ratepayers should not be responsible for paying the expenses for the cash surrender value of life insurance for former executives and recommended the $26,941 of expense be denied for ratemaking purposes.[50]

In rebuttal, Kentucky Power explained that the expense is part of the total compensation/benefit package given to executives (current or former) that should be recovered whether or not the executive is a current or a former employee.[51]

The Commission finds that the proposed expense is reasonable, and therefore the Attorney General's proposed adjustment should be denied.

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[47] Wohnhas Rebuttal Testimony at R-20.

[48] *Id.*

[49] Smith Testimony at 48.

[50] *Id.*

Rate Case Expense

The Attorney General proposed an adjustment to remove $458,333 in rate case expenses.[52] The Attorney General proposed to remove certain rate case expenses billed by a consultant who conducted witness preparation but did not sponsor testimony on Kentucky Power's behalf. The Attorney General also proposed to remove remaining rate case expenses as a penalty for Kentucky Power not seeking a reduction in the Rockport UPA ROE, which was established by the Federal Energy Regulatory Commission ("FERC").

In rebuttal, Kentucky Power argued that witness preparation is a necessary part of litigating a base rate case and that, regardless of who performs the function, the cost should be recovered.[53] Kentucky Power further argued that FERC's determination of the Rockport UPA ROE was fair, just, and reasonable, and that the decision was within FERC's exclusive jurisdiction. Kentucky Power asserted that the Attorney General's proposal to deny rate case expense as a penalty for the Rockport UPA ROE was an unlawful and unconstitutional attempt to overturn a FERC decision.

The Commission finds that the Attorney General's adjustment to remove rate case expenses for witness preparation and as a penalty for the Rockport UPA ROE is unreasonable, and should be denied. Given the type of service provided, the Attorney General's argument to remove the witness preparation consultant's fees is not

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[51] Wohnhas Rebuttal Testimony at 17.

[52] Smith Testimony at 52.

[53] Wohnhas Rebuttal Testimony at R-20.

persuasive.[54] In regard to adjusting the rate case expenses as a penalty not related to ratemaking, as set forth in *South Central Bell v. Utility Reg. Comm'n*, 637 S.W.2d 649, 653 (Ky. 1982), the imposition of penalty that is not germane to the factors that go into the ratemaking process is arbitrary and subjective. If the Attorney General objects to the ROE awarded by FERC, the appropriate forum to address that issue is at FERC, and not the Commission.

COMMISSION ADJUSTMENTS TO REVENUES AND EXPENSES

Off System Sales ("OSS") Margins, System Sales Clause Tariff ("Tariff S.S.C.")

During the test year, Kentucky Power included OSS margins in the amount of $7,163,948. Kentucky Power operated the converted Big Sandy Unit 1 for only nine months of the test period. While Kentucky Power annualized the plant maintenance expense for Big Sandy Unit 1,[55] there was no adjustment or annualization to OSS margins.

The Commission finds that OSS margins should be adjusted to reflect an annualized amount. For the 12-month period ending September 30, 2017, Kentucky Power had OSS margins of $7,650,360.[56] Therefore, the Commission will utilize the OSS margins of $7,650,360 for the 12-month period ending September 30, 2017, rather than the test year amount, resulting in an increase in operating revenue of $486,412. Additionally, the amount of OSS margins to be collected in base rates is $7,650,360, rather than the $7,163,948 proposed in the application.

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[54] *See* Kentucky Power Fifth Supplemental Response to Staff's First Request (filed Jan. 2, 2018), Item 56. The witness preparation fees were $42,623; Kentucky Power's other legal fees were $677,547.

[55] Application, Section V, Exhibit 2, Workpaper 41.

[56] Response to Commission Staff's Fourth Request for Information, Item 2.

Weather Normalized Commercial Sales

Kentucky Power proposed an adjustment to increase revenues to reflect normal temperatures, but its adjustment applied only to residential customer sales. In discovery, Kentucky Power stated that commercial revenues would have been $914,000 greater based on weather normalized temperatures.[57] After the related variable expenses are removed from revenues, the rate increase is reduced by $400,000.

The Commission finds this adjustment reasonable as temperatures affect the revenues in both the residential and commercial classes. Therefore, the Commission will reduce the rate increase by $400,000 to reflect this adjustment.

Purchased Power Limitation and Forced Outage Purchase Power Limitation Expense

Kentucky Power proposed adjustments to include the purchased power limitation and forced outage purchase power limitation expense in base rates in its application in the amount of $3,150,582 and $882,204, respectively.

As discussed under the FAC Purchase Power Limitation section below, the Commission is denying Kentucky Power's proposal to recover such costs under Tariff P.P.A. Accordingly, the Commission finds these adjustments unreasonable and should be denied.

Net Operating Income Summary

After considering all pro forma adjustments and applicable income taxes, Kentucky Power's adjusted net operating income is as follows:

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[57] Direct Testimony of Lane Kollen at 16-17.

Operating Revenues	$568,163,551
Operating Expenses	519,965,870
Adjusted Net Operating Income	$ 48,197,681

RATE OF RETURN

Capital Structure and Cost of Debt

Kentucky Power proposed an adjusted test-year-end capital structure consisting of 54.45 percent long-term debt at 5.32 percent; zero percent short-term debt at 0.80 percent; 3.87 percent accounts receivable financing at 1.95 percent; and 41.68 percent common equity at a return of 10.31 percent.[58] On August 7, 2017, Kentucky Power filed a supplement to its Application reflecting the results of Kentucky Power's June 2017 refinancing of $325 million 6.00 percent Senior Unsecured Notes, and $65 million WVEDA Mitchell Project, Series 2014A Variable Rate Demand Notes as authorized in Case No. 2016-00345.[59] This refinancing reduced the annual cost of long-term debt to 4.36 percent.[60] The capital structure proposed by the Settlement downwardly adjusts the long-term debt by one percent and places this percent onto the short-term debt at an interest rate of 1.25 percent.[61]

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[58] Application, Direct Testimony of Zachary C. Miller ("Miller Direct Testimony") at 3.

[59] Case No. 2016-00345 *Electronic Application of Kentucky Power Company for Authority Pursuant to KRS 278.300 to Issue and Sell Promissory Notes of One or More Series and for Other Authorizations* (Ky. PSC Dec. 21, 2016).

[60] Supplemental Direct Testimony of Zachary C. Miller at 5.

[61] Settlement Testimony of Mattew J. Satterwhite ("Satterwhite Settlement Testimony") at Exhibit 6a.

The Attorney General employed Kentucky Power's proposed capital structure and senior capital cost rates.[62] KCUC was silent on this topic.

Kentucky Power stated that it sells its receivables to AEP for cost savings due to default risks and to improve cash flow.[63] However, Kentucky Power's uncollectible accounts remain with Kentucky Power and are not sold with the accounts receivable.[64] The Commission notes that the cost of accounts receivable financing is higher than traditional short-term financing. The Commission believes that selling the receivables but maintaining the bad debt places an undue burden onto Kentucky Power's customers. Therefore, the Commission will blend the funds between short-term debt and accounts receivable financing so that the weighted average cost percentage of accounts receivable financing is decreased three basis points and placed on the short-term debt weighted average cost percentage. This reduces the percent of accounts receivable financing to 1.67 percent of the total capital structure and increases the percent of short-term debt to 3.20 percent of the total capital structure. The Commission finds that the cost of long-term debt and short-term debt of 4.36 percent and 1.25 percent, respectively, to be reasonable.

<u>Return on Equity</u>

In its Application, Kentucky Power developed its return on equity ("ROE") using the discounted cash flow method ("DCF"), the capital asset pricing model ("CAPM"), the empirical capital asset pricing model ("ECAPM"), and the utility risk premium ("RP"). In

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[62] Direct Testimony of J. Randall Woolridge, Ph.D. ("Woolridge Testimony") at 3.

[63] Dec. 8, 2017 H.V.T. at 12:15:22.

[64] Dec. 6, 2017 H.V.T. at 5:43:36.

addition, Kentucky Power referenced the expected earnings approach.[65] Based on the results of the methods employed in its analysis, Kentucky Power recommended an ROE range of 9.71 percent to 10.91 percent, including flotation cost.[66] Kentucky Power recommended awarding the midpoint of this range, 10.31 percent, to maintain financial integrity and to support additional capital investment.[67] Kentucky Power further stressed that consideration of all models, not just the DCF model, is important as the DCF model results may reflect the impact from the recent recession and such financial inputs are not representative of what may prevail in the near future.[68]

Direct testimony and analysis regarding ROE was provided by the Attorney General. The Attorney General employed the DCF and CAPM models for his analysis and both models were evaluated using Kentucky Power's proxy group and the Attorney General's own proxy group. This was mostly for comparison purposes, as the Attorney General stated that, on balance, the two proxy groups were similar in risk.[69] The Attorney General's DCF model results indicated equity cost rates of 8.25 percent and 8.7 percent for the Attorney General and Kentucky Power proxy groups, respectively. The Attorney General disagreed with Kentucky Power's DCF analysis, specifically noting Kentucky Power's elimination of low-end DCF results and the use of growth forecasts that the Attorney General believes are overly optimistic and upwardly biased.[70]

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[65] Application, Direct Testimony of Adrian M. McKenzie, CFA ("McKenzie Direct Testimony") at 6.

[66] *Id.* at Exhibit AMM-2 at 1.

[67] Id. at 6.

[68] Id. at 7.

[69] *Id.* at 25.

[70] *Id.* at 65.

The Attorney General's CAPM results were 7.6 percent for both proxy groups. The Attorney General stated that Kentucky Power's CAPM analysis is flawed as the ECAPM version of the CAPM was used, which the Attorney General claims makes an inappropriate adjustment to the risk-free rate and the market risk premium.[71] Additionally, the Attorney General stated that Kentucky Power's CAPM analysis employed an inflated projected interest rate, an unwarranted size adjustment, and an excessive market or equity risk premium.[72]

The Attorney General recommended relying primarily on the DCF model, determined the ROE range of the two proxy groups, 8.25 percent and 8.7 percent, to be reasonable, and recommended an ROE of 8.6 percent.[73] In support of his recommendation, the Attorney General noted that: as investment risk, Kentucky Power's credit ratings are on par with the proxy groups; capital costs for utilities remain at historical low levels and are likely to remain at low levels; the risk associated with the electric utility industry is among the lowest and, as such, the cost of equity capital is amongst the lowest; and authorized ROEs have been gradually decreasing in recent years.[74]

The Attorney General also disagreed with Kentucky Power's upward adjustment of 0.11 percent to the equity cost rate recommendation to account for flotation costs. The Attorney General argued that Kentucky Power did not identify any flotation costs

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[71] *Id.* at 68.

[72] *Id.*

[73] Woolridge Testimony at 58.

[74] *Id.* at 59.

that are specifically associated with Kentucky Power.[75] The Attorney General stated that it is commonly argued that a flotation cost adjustment is necessary to recover issuance costs, but should not be recovered through the regulatory process, as these costs are already known to the investor upon buying the stock.[76]

The parties to the Settlement agreed that the revenue requirement increases for Kentucky Power will reflect a 9.75 percent ROE as applied to Kentucky Power's capitalization and capital structure of the proposed revenue requirement increases as modified through discovery. As a result, use of a 9.75 percent ROE reduced Kentucky Power's proposed electric revenue requirement by $4.7 million.[77] In his post hearing brief, the Attorney General recognized the significant reduction from the original ROE, but still believes it is in excess of the return shareholders require.[78] The Attorney General further argued that utilities seem to overstate necessary ROE, and does not support the 9.75 percent.[79] For the reasons discussed below, the Commission finds a ROE of 9.75 percent to be unreasonable, and for the purpose of base rate revenues and certain tariffs, an ROE of 9.70 percent should be applied.

In his testimony, the Attorney General noted that differing opinions between Kentucky Power and the Attorney General regarding capital market conditions result in differing ROE recommendations.[80] Kentucky Power's analysis assumes higher interest

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[75] *Id.* at 80.

[76] *Id.* at 81.

[77] Settlement at 4.

[78] Attorney General's Post Hearing Brief ("Attorney General's Brief") (filed Jan. 5, 2018) at 18.

[79] *Id.* at 19 and 20.

[80] Woolridge Testimony at 5.

rates and capital costs whereas the Attorney General concludes that interest rates and capital costs are at low levels and likely to remain low for some time.[81] The Commission agrees with the Attorney General that, although interest rates are increasing, they are doing so slowly and are still historically low. In fact, the Federal Reserve noted the following:

> The Committee expects that economic conditions will evolve in a manner that will warrant gradual increases in the federal funds rate; the federal funds rate is likely to remain, for some time, below levels that are expected to prevail in the longer run. However, the actual path of the federal funds rate will depend on the economic outlook as informed by incoming data.[82]

The Commission further agrees that models supporting the low interest rate environment should be given more weight than those supporting high interest rate expectations.

The Commission also agrees with the Attorney General that flotation costs should be excluded from the analysis. The Commission believes that flotation costs are accounted for in the current stock prices, as the price includes the underwriting spread and adding the adjustment amounts to double counting. Removal of the flotation costs from Kentucky Power's initial cost of equity range lowers the range to 9.6 percent from 10.8 percent.[83]

The 2017 economic environment has shown signs of relative improvement. In response to low inflation and low unemployment, the Federal Reserve increased interest rates a quarter of a percent three times in 2017. Current outlooks for 2018 are

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[81] *Id.*

[82] Testimony of Richard A. Baudino at 8.

[83] McKenzie Direct Testimony, Exhibit AMM-2 at 1.

healthy, with gross domestic product growth rates expected to remain between two and three percent, unemployment forecasted to continue at the natural rate, and inflation expected to hover at around two percent.[84] However, notwithstanding these improvements, the economy of Eastern Kentucky has lagged behind national and state trends. Employment trends have not recovered to pre-recession levels, earnings trends remain stagnant and lag behind the state trends, and poverty rates in the majority of Kentucky Power's service territory are 24.4 percent or higher.[85]

The Commission is cognizant of the risk inherent to Kentucky Power's service territory and load profile. The Commission notes the Attorney General's position that Eastern Kentucky has been economically depressed for the past decade and that the Commission should consider the economic conditions of the region in evaluating the overall rates and rate design.[86] Therefore, given the adverse economic situation of the service territory of high unemployment, low earnings, and high poverty rates, the Commission finds a lower ROE will allow Kentucky Power to earn a fair return while reflecting the economic situation of its customers.

For 2016, the median ROE of the utilities in the Attorney General's proxy group was 9.3 percent; for Kentucky Power's proxy group, the median ROE was 9.4 percent.[87] In addition, the average authorized ROE reported by SNL Financial for 2017 is

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[84] https://www.thebalance.com/us-economic-outlook-3305669.

[85] Attorney General's Brief at 12; Dismukes Testimony at 5-6; Dec. 6, 2017 H.V.T., PSC Exhibit 1.

[86] Dismukes Testimony at 6.

[87] Woolridge Testimony, Exhibit JRW-4 at 1.

approximately 9.7 percent.[88] The Commission agrees with Kentucky Power that this is a benchmark worthy of consideration, but disagrees that a downward adjustment will be injurious to customers and the Kentucky economy.[89] Based on the entire record developed in this proceeding, we find that an ROE of 9.7 falls within the range of the Attorney General's proposed 8.6 percent to the initial proposed ROE of 10.31 percent, and within Kentucky Power's original range of 9.6-10.8 percent, adjusted for flotation costs. Additionally, an ROE of 9.7 is within the range of the benchmarks provided by SNL, the proxy groups, and recent Commission Orders[90].

Rate-of-Return Summary

Applying the rates of 4.36 percent for long-term debt, 1.25 percent for short-term debt, 1.95 percent for accounts receivable financing, and 9.70 percent for common equity to the Commission adjusted capital structure produces an overall cost of capital of 6.44 percent.[91] The cost of capital produces a return on Kentucky Power's rate base of 6.42 percent.

BASE RATE REVENUE REQUIREMENTS

In the Settlement, Kentucky Power and the Settling Intervenors agreed to a base rate increase of $31.8 million. The Attorney General's expert witness proposed a base

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[88] Direct Testimony and Exhibits of Gregory W. Tillman on behalf of Wal-Mart Stores East, LP and Sam's East, Inc. at 11.

[89] Rebuttal Testimony of Adrien M. McKenzie, CFA at 73.

[90] Case No. 2016-00370 Electronic Application of Kentucky Utilities Company For An Adjustment Of Its Electric Rates and For Certificates of Public Convenience and Necessity (Ky. PSC Jun. 22, 2017) and Case No. 2016-00371 Electronic Application of Louisville Gas and Electric Company For An Adjustment Of Its Electric and Gas Rates and For Certificates Of Public Convenience and Necessity (Ky. PSC Jun. 22, 2017).

rate increase of $39.8 million. The Commission finds that, subject to the adjustments discussed in this Order, a base rate increase of $12.35 million is reasonable, as is discussed in the Total Jurisdictional Revenue Requirement section below.

REVENUE REQUIREMENT-RELATED RIDERS AND DEFERRALS

Big Sandy Retirement Rider

In its Application, Kentucky Power proposed to rename the Big Sandy Retirement Rider to the Decommissioning Rider to alleviate customer confusion regarding the purpose of the rider. Pursuant to the settlement agreement approved in Case No. 2014-00396, Kentucky Power recovers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2, and other site-related retirement costs through this rider. Only the rider name will change; the rider will continue to operate in the manner approved by the Commission in Case No. 2014-00396.

The Commission finds the name change reasonable and that it should be approved. The Commission further finds that the carrying charges associated with this rider should be based on the weighted average cost of capital ("WACC"), after reflecting the impacts of the reduction in the federal corporate income tax rates approved in this Order, should become effective as of the date of this Order. However, the monthly amounts collected will not change until Kentucky Power makes its annual filing on or before August 15, 2018, to adjust the amounts collected under this rider.

Big Sandy Unit 1 Operation Rider

In its Application, Kentucky Power proposed to eliminate the Big Sandy Unit 1 Operation Rider ("Tariff B.S.1.O.R.") and to recover through base rates the costs

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[91] The Commission adjusted capital structure consists of 54.45 percent long-term debt, 3.2

currently recovered through Tariff B.S.1.O.R. Once new rates become effective in this case, Tariff B.S.1.O.R. will have an under- or over-recovery balance. Therefore, Kentucky Power also requested authority to establish a regulatory asset or liability that will allow Kentucky Power to track and defer any under- or over-recovery balance until its next rate case.

In Case No. 2014-00396, the Commission approved Tariff B.S.1.O.R. to permit Kentucky Power to recover the non-fuel costs of operating Big Sandy Unit 1 as a coal burning unit until its conversion to natural gas, the non-fuel costs of its operation as a natural gas unit and capital investment required for its conversion to natural gas once it is placed in service. Tariff B.S.1.O.R. was designed to be in effect until the rates established in Kentucky Power's next base rate case were implemented.

The Commission has previously approved regulatory assets for other jurisdictional utilities. Such approval has been granted when a utility has incurred: (1) an extraordinary, nonrecurring expense which could not have reasonably been anticipated or included in the utility's planning; (2) an expense resulting from a statutory or administrative directive; (3) an expense in relation to an industry-sponsored initiative; or (4) an extraordinary or nonrecurring expense that over time will result in a saving that fully offsets the cost.[92] Since Tariff B.S.1.O.R. was approved by the Commission in Case No. 2014-00396, the establishment of a regulatory asset to address the under-

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percent of short term debt, 1.67 percent of accounts receivable financing, and 41.68 percent of common equity.

[92] Case No. 2008-00436, *The Application of East Kentucky Power Cooperative, Inc. for an Order Approving Accounting Practices to Establish a Regulatory Asset Related to Certain Replacement Power Costs Resulting from Generation Forced Outages* (Ky. PSC Dec. 23, 2008), at 4. *See also* Case No. 2010-00449, *Application of East Kentucky Power Cooperative, Inc. for an Order Approving the Establishment of a Regulatory Asset for the Amount Expended on Its Smith 1 Generating Unit* (Ky. PSC Feb, 28, 2011), at 7.

recovery of Tariff B.S.1.O.R. is consistent with the second example listed above. Regarding a possible regulatory liability, the Commission notes that it is appropriate that Kentucky Power customers be the beneficiaries of any over-recovery of Tariff B.S.1.O.R.

The Commission finds the establishment of a regulatory asset or liability due to the elimination of Tariff B.S.1.O.R. to be reasonable and that it should be approved. This approval is for accounting purposes only, and the appropriate ratemaking treatment for the regulatory asset or liability account will be addressed in Kentucky Power's next general rate case.

Tariff A.T.R.

In its Application, Kentucky Power proposed to eliminate Tariff Asset Transfer Rider ("Tariff A.T.R."). Given that Kentucky Power has recovered the full amount that Tariff A.T.R. was designed to recover, the Commission finds the elimination of Tariff A.T.R. to be reasonable and that it should be approved.

Tariff K.E.D.S.

In its Application, Kentucky Power proposed to increase Tariff K.E.D.S. from $0.15 per meter per month to $0.25 per meter per month. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a surcharge of $0.10 per meter for residential customers and $1.00 per meter for non-residential customers. KCUC did not provide testimony regarding Tariff K.E.D.S.

Tariff K.E.D.S. imposes an economic development surcharge, which was approved in Kentucky Power's last rate case,[93] to fund economic development initiatives

[93] Case No. 2014-00396, Final Order at 49-51.

in Kentucky Power's service territory, with funds collected through the surcharge matched equally by Kentucky Power from AEP shareholder funds. As a basis for the increase, Kentucky Power argued that additional economic development funds were needed to grow its load and customer base. One of the reasons for Kentucky Power's proposed rate increase is a significant decline in load and customers since the economic downturn in 2008.[94] A decrease in customers and load concentrates costs among a smaller customer base, which results in fewer customers paying a larger share of the cost. Correspondingly, a growth in load and customer base spreads costs among a greater number of customers.

The Attorney General recommended that the economic development surcharge be eliminated.[95] The Attorney General asserted that Kentucky Power failed to provide evidence of a direct tie between Kentucky Power's economic development efforts and increased jobs and electricity sales.[96] The Attorney General further asserted that the economic development surcharge simply redistributes ratepayer dollars without evidence of an identifiable benefit for ratepayers.

In rebuttal, Kentucky Power countered that it maintains economic development metrics, including job counts, investments, and grants, which it uses to evaluate the

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[94] Application, Direct Testimony of Brad N. Hall ("Hall Direct Testimony") at 5. Between 2008 and 2016, Kentucky Power lost 6,931 customers, and its total annual sales declined from 7.24 GWh to 5.80 GWh.

[95] Direct Testimony of David E. Dismukes ("Dismukes Testimony") at 4; Direct Testimony of Roger McCann ("McCann Testimony") at 6, 17.

[96] Dismukes Testimony at 4, 41.

success of its economic development program.[97] In a subsequent discovery response, Kentucky Power provided its written economic development action plan with strategic goals and metrics set forth in specific detail.[98] Kentucky Power contended that its economic development program achieves identifiable goals, and that Kentucky Power's customers receive benefits from the economic development surcharge. As an example, Kentucky Power asserted that its economic development efforts are projected to create 1,705 new full-time positions, with an additional 1,000 construction jobs.[99]

The Commission recognizes the importance of economic development efforts, especially given the economic needs of Kentucky Power's service area. However, the Commission also recognizes that 26 percent, or 35,756, of Kentucky Power's residential customers are at or below the poverty level.[100] In 2016, Kentucky Power disconnected more than 11,000 residential customers who could not pay their electric bill.[101] In the course of this proceeding, the Commission received a large number of public comments from residential customers who questioned why they are charged for Kentucky Power's economic development efforts, particularly given the difficulty that residential customers have in paying their electric bills. Residential customers, especially those on fixed incomes, cannot pass along their costs; to a certain extent, non-residential customers

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[97] Dec. 8, 2017 H.V.T. at 10:44:56.

[98] Kentucky Power Response to KCUC's Post Hearing Data Request ("Response to KCUC Post Hearing Request"), Item No. 1, Attachment 1.

[99] Hall Direct Testimony at 12; Dec. 8, 2017 H.V.T. at 10:31:23. On December 7, 2017, there was an announcement that 875 jobs would result from a business locating in Pikeville, Kentucky. Prior to that announcement, there were 830 projected new jobs created from Kentucky Power economic development efforts.

[100] Dec. 8, 2017 H.V.T. at 11:58:01 and 5:33:49.

[101] *Id.* at 11:58:19.

can pass along their costs to their customers. The Commission finds that the residential customer economic development surcharge of $0.10 per meter per month, as set forth in the Settlement, is unreasonable and therefore should be denied. The Commission further finds that the residential customer economic development surcharge should be eliminated. However, the Commission finds that the economic development surcharge on non-residential customers of $1.00 per meter per month, as set forth in the Settlement, is reasonable. Therefore, the Commission approves the portion of the Settlement applicable to the economic development surcharge for non-residential customers only.

Home Energy Assistance Program Surcharge

In its Application, Kentucky Power proposed to increase the HEAP surcharge from $0.15 per residential meter per month to $0.20 per residential meter per month. Similar to the economic development surcharge, funds collected through the HEAP surcharge are matched equally by Kentucky Power from AEP shareholder funds.

HEAP funds provide subsidies to assist eligible low-income customers in Kentucky Power's service territory to pay electric bills during seven peak heating and cooling months.[102] There is a waiting list of eligible customers because there are not sufficient HEAP funds available to assist all eligible customers.[103]

The Attorney General supported the five-cent increase to $0.20 per residential meter per month, but argued that the increase was inadequate to keep pace with

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[102] McCann Testimony at 5-6, 14. Subsidies are available in January, February, March, July, August, September, and December.

[103] *Id.* at 15. As of Sept. 20, 2017, there were 1,475 eligible customers on a wait-list for HEAP subsidies.

Kentucky Power's rate increases. The Attorney General proposed that the Commission approve the HEAP surcharge increase and, if the Commission discontinued the economic development surcharge, that the HEAP surcharge be increased in the same amount by which the economic development is reduced.[104]

Kentucky Power's President, Matthew J. Satterwhite, testified that, if the Commission modified the Settlement to eliminate the $0.10 per meter per month economic development surcharge for residential customers, Kentucky Power could agree to a commensurate increase in the HEAP surcharge by $0.10 per residential meter per month, with matching shareholder funds.[105]

The Settlement is silent as to the HEAP surcharge.

The Commission finds that the proposed increase in the HEAP surcharge is insufficient to address the demonstrable need to assist eligible low-income customers with their electric bills. The Commission further finds that the HEAP surcharge should be increased by the corresponding amount that the economic development surcharge for residential customers is reduced. Therefore, the Commission rejects Kentucky Power's proposed increase in the HEAP surcharge to $0.20 per residential meter per month. The Commission finds an increase of the HEAP surcharge to $0.30 per residential meter per month is reasonable and should be approved.

<u>Rockport Deferral Mechanism</u>

In the Settlement, Kentucky Power and the Settling Intervenors agreed to defer $50 million of non-fuel and non-environmental lease expenses from Rockport Unit 2

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[104] McCann Testimony at 6, 17; Dismukes Testimony at 4.

over five years, with the establishment of a regulatory asset for later recovery ("Rockport Deferral Regulatory Asset") of these expenses. This Rockport Deferral Regulatory Asset, plus a carrying charge based on a WACC of 9.11 percent, will be recovered through Kentucky Power's Tariff P.P.A. over five-years starting in December of 2022. The dates of the end of the deferral period and the start of the five-year amortization period coincide with the anticipated end of the Rockport UPA lease agreement.[106]

The Settlement proposed a deferral of $15 million in 2018 and 2019, $10 million in 2020, and $5 million in 2021 and 2022. The Settlement's annual revenue requirement reflects a decrease to base rates of the 2018 $15 million adjustment. In 2020, 2021 and 2022 the decrease in the deferral will be offset with an increase in the amount recovered through Tariff P.P.A. Additionally, in 2022, the increase in the amount recovered through Tariff P.P.A. will be prorated through December 8, 2022, as the Rockport UPA will terminate on that date. By utilizing Tariff P.P.A., Kentucky Power is able to reduce the annual deferral amount and concurrently keep base rates unchanged. Beginning in December 2022, the five-year deferral period will end and the recovery of the Rockport Deferral Regulatory Asset will begin. The Rockport Deferral Regulatory Asset will be amortized through 2027 and be subject to carrying charges until it is fully recovered. Kentucky Power estimates that the Rockport Deferral

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[105] Dec. 7, 2017 H.V.T. at 10:53:09.

[106] Satterwhite Settlement Testimony at S-10.

Regulatory Asset will total approximately $59 million in December 2022. That amount will decrease incrementally until fully collected over the five-year amortization period.[107]

Neither the Attorney General nor KCUC offered testimony concerning the Rockport Deferral. However, during the hearing and in his post-hearing brief, the Attorney General expressed his concerns about the "very large financing costs" associated with the deferrals, stating that the "$50M over the entire deferral period is going to have financing costs piled on top of it... [t]hese financing costs are at the weighted average cost of capital including the 9.75 percent return of equity which then gets a tax gross up on top of it."[108] The Attorney General further stated that a concern that the costs of the deferral will eventually require rate recovery in future rate proceedings.[109] The Attorney General recommended that the carrying charge be reduced to 4.36 percent for Kentucky Power's current long term debt.[110]

In response, Kentucky Power argued that the 9.11 percent WACC made Kentucky Power financially whole because of its need to finance the deferral through a combination of debt and equity, and therefore was appropriate.[111]

The recovery period of the proposed Rockport Deferral Mechanism is contingent upon Kentucky Power not renewing the Rockport UPA.[112] If the lease is not renewed,

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[107] *See* Appendix A, paragraph 3 for details of the Rockport UPA Expense Deferral.

[108] Dec. 6, 2017 H.V.T. at 04:01:19; *See also* Attorney General's Brief at 31.

[109] Dec. 6, 2017 H.V.T. at 04:01:19

[110] Attorney General's Brief at 31.

[111] Kentucky Power's Post Hearing Brief ("Kentucky Power's Brief") (filed Jan. 5, 2018) at 48.

[112] Kentucky Power stated that it is unlikely that the Rockport lease will be renewed. Dec. 6, 2017 H.V.T. at 5:47:44; Kentucky Power Response to Staff's Second Request, Item 72.

the expenses associated with the Rockport UPA will be removed from rate base, which allows the regulatory asset to be funded without a change in rate base. However, if the lease is renewed, the deferred expenses will have to be recovered from future ratepayers, and possibly through an increase in rate base.[113] The Commission recognizes that there are inherent risks associated with any deferral mechanism, especially since the deferral recovery is contingent upon not renewing the Rockport UPA. Given Kentucky Power's excess capacity and slow load growth, the Commission believes the benefits of the deferral outweigh the associated risks, and approves the Rockport Deferral Mechanism and the associated $15 million decrease to rate base. The carrying charges associated with this rider shall be based on the WACC approved in this Order and are effective as of the date of this Order. This approval is for accounting purposes only, and the appropriate ratemaking treatment for this regulatory asset account will be addressed in Kentucky Power's next general rate case.

Environmental Surcharge Tariff E.S.

Kentucky Power proposed an addition to its Environmental Compliance Plan to recover the cost of installing Selective Catalytic Reduction ("SCR") technology at Rockport Unit 1, affecting the amounts collected under Tariff E.S The project is discussed later in the Environmental Compliance Plan section of this Order. Kentucky Power estimated the revenue requirement for the SCR project to be $3,903,065.[114] The Commission finds the Rockport Unit 1 revenue requirement to be reasonable.

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[113] Satterwhite Settlement Testimony at S-13.

[114] Elliott Testimony, Exhibit AJE-5.

TOTAL JURISDICTIONAL REVENUE REQUIREMENTS

The Commission has found that Kentucky Power's required ROE falls within a range of 8.60 percent to 10.31 percent, and approves an ROE of 9.70 percent. The Settlement proposed a base rate increase of $31.8 million and environmental surcharge revenues of $3.9 million, for a total of $35.7 million. The environmental surcharge is discussed farther below. Because Kentucky Power recovers the costs associated with the decommissioning of coal-related assets at Big Sandy through the Decommissioning Rider, those costs are not included for recovery in the base rates. However, for the twelve months ending September 30, 2018, Kentucky Power will recover approximately $20.2 million through the Decommissioning Rider,

Due to the modifications the Commission makes to the Settlement and the provision for the reduction in the federal corporate income tax rate from 35 percent to 21 percent in the Tax Cuts and Jobs Act, the Commission finds that an increase in base rate revenues of $12.35 million, as shown in Appendix F to this Order, exclusive of the environmental surcharge, will result in fair, just, and reasonable electric rates for Kentucky Power and its ratepayers. The Commission utilized Kentucky Power's equity gross up revenue conversion factor ("GRCF"), as provided in Kentucky Power's revised Environmental Surcharge forms filed on January 3, 2018, to reflect the reduction in the federal corporation income tax rate effective with the date of this Order. Additionally, the adjustments the Commission makes to the test year operating income and expense items reflect the income tax rate reduction and change in the GRCF. The excess accumulated deferred income tax ("ADIT") impacts resulting from the reduction federal corporate income tax rate will be addressed in Case No. 2017-00477. The Commission also finds that Kentucky Power should establish a mechanism to track the over/under-collection of federal income taxes, and that a true-up of any over/under-collections be addressed in Case No. 2017-00477.

Due to the economic conditions in Kentucky Power's service territory, the Commission believes that the impact of the federal corporate income tax reduction on rates should be put into place effective with the date of this Order. In addition, the lower rates should serve as an impetus for economic development through recruiting new businesses as well as maintaining existing business customers.

NONREVENUE REQUIREMENT RIDERS AND TARIFFS

The following sections address riders and a tariff that have no direct impact on Kentucky Power's revenue requirement. The discussion covers both those that have been contested, and those that are included in the Settlement.

Non-Utility Generator Tariff

In its Application, Kentucky Power proposed to revise the Non-Utility Generator Tariff ("Tariff N.U.G.") to eliminate a provision that requires a 30-day written notice to customers taking service under Tariff N.U.G. if a transmission provider implements charges for transmission congestion. Kentucky Power asserted that this clause is no longer necessary because PJM has already created transmission congestion charges.[115] Kentucky Power also proposed to revise language in the special terms and conditions section of Tariff N.U.G. to clarify the requirement to take service for remote

[115] Application, Vaughan Direct Testimony at 25.

self-supply.[116] The Settlement is silent as to Tariff N.U.G. Neither KCUC nor the Attorney General contested the proposed revisions to Tariff N.U.G.

The Commission finds the revisions to Tariff N.U.G. to be reasonable and that they should be approved.

Systems Sales Clause

In its Application, Kentucky Power proposed to reduce monthly bill volatility by revising its Tariff S.S.C. to change from a monthly system sales adjustment factor to an annual sales adjustment factor. Kentucky Power further proposed to set the Tariff S.S.C. rate to $0, with the difference between actual off-system sales margins and a base amount of $7,163,948 deferred based on the current 75/25 customer sharing mechanism approved in Case No. 2014-00396.[117] The net deferred credit or charge to customers would then be the base for the annual Tariff S.S.C. rate update.[118] Kentucky Power proposed to file the required true-up information no later than August 15 of each year, with rates to be effective with Cycle 1 of October. The first filing would be made by August 15, 2018. The Settlement is silent as to Tariff S.S.C. Neither the Attorney General nor KCUC contested the proposed revisions to Tariff S.S.C.

The Commission finds the revisions to Tariff S.S.C., as adjusted to include $7,650,350 in base rates, to be reasonable and should be approved.

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[116] Sharp Direct Testimony at 28.

[117] Kentucky Power credits 75 percent of the difference between base and actual off system sales margins amounts to customers and retains 25 percent.

[118] Vaughan Direct Testimony at 36-37.

PJM Billing Line Items

In the Application, Kentucky Power proposed to include additional PJM Billing Line Items ("BLIs") for recovery through its FAC. Kentucky Power stated that these BLIs represent items that either require generation resources to be running and online, or are associated with other BLIs that require generation resources to be running and online. Kentucky Power stated that all of the service functions represented by the BLIs are related to fuel-related services previously received by Kentucky Power when it was a member of the AEP East Pool, and that those amounts were previously included in Kentucky Power's base fuel cost. The Settlement is silent as to the BLIs. Neither the Attorney General nor KCUC contested this proposal.

The Commission has reviewed the additional BLIs and finds that they are appropriate for inclusion in the FAC, as these BLIs represent charges and credits that relate to fuel consumed by resources that are running and online. Furthermore, the Commission finds that when Kentucky Power files its compliance tariff, it should amend its Tariff F.A.C to include PJM BLIs 2211, 2215, and 2415, as those BLIs have replaced BLI 2210.

MODIFICATIONS TO TERMS AND CONDITIONS OF SERVICE TARIFFS

In its Application, Kentucky Power proposed certain revisions to its terms and conditions for service. The revisions include: verification of a customer's identity and proof of ownership or lease of property where service is requested at the time an application for service is filed; information to be considered when evaluating whether to waive a deposit; payment arrangements; mobile alerts; elimination of the employee discount; modifying the equal payment plan; and denial or discontinuance of service.

Kentucky Power also requested a deviation from 807 KAR 5:006, Section 14(2)(a) to amend when a customer can sign up for the Equal Payment Plan, and the annual settle-up month for certain customers.

Neither the Attorney General nor KCUC contested the revisions.

The Commission finds that the proposed revisions to the terms and conditions of service as contained in the Application are reasonable, with the exception of the denial or discontinuance of service, and should be approved. The Commission further finds that Kentucky Power established good cause to deviate from 807 KAR 5:006, Section 14(2)(a), and that its request for a deviation should be granted.

As to the denial or discontinuance of service, the Commission finds that the proposed revisions as contained in the Application are overbroad and do not comply with Commission precedent.[119] In response to Commission Staff's Post Hearing Data Request, Kentucky Power revised the terms for denial or discontinuance of service as follows:

> The Company reserves the right to refuse or discontinue service to any customer if the customer is indebted to the Company for any service theretofore rendered at any location. Service will not be supplied or continued to any premises if at the time of application for service the Applicant is merely acting as an agent of a person or former customer who is indebted to the Company for service previously supplied at the same, or other premises, until payment of such indebtedness shall have been made;

The Commission finds that the revised language regarding denial or discontinuance of service as filed on in the Supplemental Response on December 21, 2017, is reasonable and should be approved.

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[119] *See* H.V.T., PSC Exhibits 2, 3, 4, and 6.

RATE DESIGN, TARIFFS AND OTHER ISSUES

Rate Design

Kentucky Power filed a fully allocated jurisdictional cost-of-service study ("COSS") to determine the cost to service each customer class as well as the rate of return on rate base for each class during the test year. The results of the COSS illustrate the amount of cross-subsidization between the rate classes and show that all non-residential rate classes subsidize the residential class. In its Application, Kentucky Power proposed to reduce these subsidies by five percent in its proposed rates. The Settlement modifies this proposed revenue allocation and proposes to use the first $5.8 million of any Commission-authorized revenue increase to the Industrial General Service ("IGS") rate class to fully eliminate the subsidy Rate IGS would have paid under the rate increase as originally proposed by Kentucky Power.[120] The remaining revenue increase is spread uniformly among the rate classes, further reducing interclass subsides.[121]

The Attorney General did not offer any testimony concerning the allocation of any proposed revenue increase, aside from recommending limiting any revenue increase, and stating that Kentucky Power's customers are unable to afford a rate increase and that a large increase would set the entire economy of Eastern Kentucky back, counteracting any economic expansion.[122]

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[120] Satterwhite Settlement Testimony at S-9; Dec. 8, 2017 H.V.T. at 2:59:20; Direct Testimony of Stephen J. Baron ("Baron Testimony") at 15 and Table 2.

[121] Satterwhite Settlement Testimony at S-9.

[122] Dismukes Testimony at 3.

The KCUC does not support the revenue allocation as set forth in the Settlement, contending that the Settlement does not provide fair or reasonable treatment of the Tariff L.G.S. customer class. KCUC stated that in addition to bearing a subsidy burden associated with the overall rate structure, the L.G.S. class must also absorb an additional $500,000 subsidy resulting from the Public and Private School service ("PS") tariff.[123] To remedy this, the KCUC proposes that the first $500,000 of any additional Commission-directed decrease in the revenue requirement be applied to the Tariff L.G.S. customer class and any revenue reduction beyond $500,000 be uniformly spread among all the rate classes in proportion to each class's revenue requirement.[124]

Residential Customer Charge

In its Application, Kentucky Power proposed an increase in the residential customer charge from $11.00 to $17.50, an increase of 59 percent. The cost-of-service study filed by Kentucky Power in this proceeding supports a customer charge of $37.88.[125] The Settlement allows for an increase in the residential customer charge to $14.00, an increase of 27 percent.

The Attorney General objected to any increase on the residential customer charge.[126] The Attorney General contended that shifts towards fixed cost recovery disproportionally hurt low-income customers and Kentucky Power did not provide

[123] Settlement Testimony of Kevin Higgins ("Higgins Settlement Testimony") at 2.

[124] *Id.* at 4.

[125] Vaughan Direct Testimony, Exhibit AEV-2 at 1.

[126] Dismukes Testimony at 6.

sufficient evidence to justify an increase.[127] The Attorney General argued that Kentucky Power's fixed cost calculation of almost $38.00 is flawed because a portion of demand-related costs are assigned as fixed costs, which the Attorney General argued is fundamentally incorrect.[128] The Attorney General noted that none of the parties to the proposed Settlement represent the interests of residential ratepayers, and the proposed $14 would recover too much of any potential revenue increase through the customer charge and undermine future incentives for efficiency, resulting in an erosion of LIHEAP funds.[129]

The Commission believes an increase to the Residential Basic Service Charge is warranted, and finds that the Settlement's increase to $14.00 is reasonable. The proposed 27 percent increase is consistent with the principle of gradualism that the Commission has long employed. Consistent with this change, the Commission also approves the customer charges of $14.00 as set forth in the Settlement for the three optional residential tariffs: 1) Residential Service Load Management Time-of-Day; 2) Residential Service Time-of-Day; 3) and Experimental Residential Service Time-of-Day 2. The Commission also approves a customer charge of $14.50 for the new optional Residential Demand Metered Electric Service ("Tariff R.S.D.").[130]

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[127] *Id.*

[128] *Id.* at 20.

[129] Attorney General's Brief at 32-33.

[130] The Settlement and supporting testimony state that Kentucky Power and the Settling Intervenors agreed to a residential customer charge of $14.00. Settlement at paragraph 16(a); Satterwhite Settlement Testimony at S-22. The proposed Settlement Tariff R.S.D. filed on Dec. 1, 2017, inadvertently contains a monthly customer charge of $17.50.

General Service Rate Class

Kentucky Power proposed to combine the Small General Service ("S.G.S.") and Medium General Service ("M.G.S.") rate classes into a single General Service ("G.S.") rate class under which all general service customers with average demands up to 100 kilowatts ("kW") will take service. Kentucky Power stated that both the S.G.S. and M.G.S. rate classes currently incur a monthly service charge and a blocked energy charge. Additionally, the M.G.S. rate class incurs a demand charge. Due to this current tariff structure, there is movement between the S.G.S. and M.G.S. rate classes as load characteristics vary month to month for many commercial customers. Kentucky Power stated that combining the S.G.S. and M.G.S. into a single tariff allows for administration efficiencies by eliminating this movement between the two rate classes.[131] The new G.S. tariff combines rate design features from the S.G.S. and M.G.S. tariffs, and will include a monthly service charge, two blocked energy charges, and a demand charge for monthly billing demand greater than 10 kW. The blocked energy charge transition point is 4,450 kilowatt hours ("kWh"). Kentucky Power stated that setting the kWh block at 4,450 kWh ensures that almost all usage that was billed under the current S.G.S. tariff will continue to be billed on an energy charge only and such a rate design will minimize bill impact on current S.G.S. and M.G.S. customers.[132]

Although the proposed rate design minimizes the impact on an average commercial customer, due to the proposed increase in the demand charge from $1.91

[131] Vaughan Direct Testimony at 21.

[132] *Id.* at 21.

for all kW to $7.95 for all kW greater than 10 kW, it negatively affects customers whose load characteristics include low usage coupled with high demand.[133] The Commission believes that Kentucky Power's proposed increase in the demand charge of over 300 percent is excessive. For this reason, the Commission will minimize the impact on high demand commercial customers, apply a 2-step phase-in increase of demand rates, and limit the increase in year 2 to $6.00 per kW. In addition, Kentucky Power must identify and contact G.S. class customers whose average monthly demand is 25 kW or greater to meet to discuss the impacts of the rate increase on those customers' bills and analyze other tariff options, such as time-of-day rates, that may offer relief to these customers. Last, Kentucky Power should file with the Commission, within twelve months of this Order, a report listing the commercial customers who meet this load profile and the results of each meeting.

Rate Adjustment

In setting the rates shown in Appendix C, the Commission maintained the basic service charge for each class that was included in the Settlement. The reduction of Kentucky Power's revenue increase was allocated to the energy charges of those customer classes for which revenue increases were proposed. The reduction to each class's proposed revenue increase was approximately in proportion to the increase set forth in the Settlement.

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[133] Dec. 8, 2017 H.V.T. at 4:53:40.

Tariff Purchased Power Adjustment

In its Application, Kentucky Power proposed to include the following additional cost of service items to be tracked and recovered through Tariff P.P.A.: (1) PJM OATT charges and credits that it incurs or receives from its participation as a LSE in the organized wholesale power markets of PJM; (2) purchased power costs excluded from recovery through the FAC as a result of the purchased power limitation; and (3) gains and losses from incidental gas sales. In addition, Kentucky Power proposed to change Tariff P.P.A. from a monthly adjusting surcharge to an annually updated surcharge.

The Attorney General filed testimony stating that these cost-of-service items should continue to be collected through base rates as Kentucky Power has not demonstrated a compelling reason to have these items tracked and recovered through Tariff P.P.A.[134]

1. PJM LSE OATT Charges and Credits

Kentucky Power proposed to include the following PJM LSE transmission charges and credits to costs recoverable through Tariff P.P.A.: network integration transmission service ("NITS"); transmission owner scheduling system control and dispatch service ("TO"); regional transmission expansion plan ("RTEP"); point-to-point transmission service; and RTO start-up cost recovery. An adjusted level of the net OATT charges and credits in the amount of $74,377,364 will be included in base rates.[135] The amount above or below the base rate level would be tracked monthly and the annual net over- or under-collection would then be collected from or credited to customers through the operation of Tariff P.P.A.

[134] Smith Testimony at 70.

Kentucky Power stated that the proposed tracking mechanism for PJM OATT LSE Charges is necessary due to the volatility of these PJM charges and credits, which Kentucky Power claimed are largely out of its control. Kentucky Power estimated that its PJM OATT LSE expenses will increase in 2018 by approximately $14 million, or 19 percent over the test year amount.[136] Kentucky Power expects increasing investment in the transmission grid by PJM member transmission owners, which will increase transmission charges allocated to LSEs in PJM. Kentucky Power stated that tracking the PJM LSE charges and credits via Tariff P.P.A. could preclude it from seeking more frequent rate cases.[137]

Finally, two proceedings currently before the FERC may affect the level of PJM LSE OATT charges incurred by Kentucky Power. One proceeding is a challenge to the ROE included in the AEP Zone formula, which determines the PJM transmission costs of service for the AEP Transmission Zone. Kentucky Power stated that at this time, any change resulting from this proceeding is not known and measurable. Therefore, an adjustment in this case is not possible. The second proceeding is a pending non-unanimous settlement regarding the cost allocation methodology historically used by PJM to allocate costs of transmission enhancement projects to the LSEs in its footprint. If approved, the proposed stipulation is expected to result in lower PJM LSE OATT

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[135] Vaughan Direct Testimony at 29.

[136] Satterwhite Settlement Testimony at S-14–S-15.

[137] Vaughan Direct Testimony at 27-28.

charges. However, the timing or magnitude of the possible cost allocation changes are not currently known.[138]

The Settlement revised the proposal regarding the PJM OATT LSE charges and credits as follows:

- Kentucky Power will recover and collect 80 percent of the annual over- or under-collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through Tariff P.P.A.

- Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100 percent of the difference between the return on its incremental transmission investments calculated using the FERC approved PJM OATT return on equity, and the return on its incremental transmission investments calculated using the 9.75 percent return on equity provided for in the settlement.

- The changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise extended by the Commission.

Due to the volatility of the OATT charges and credits, the Commission finds the proposal to include the PJM LSE transmission charges and credits to the costs recoverable through Tariff P.P.A., as modified in the Settlement, reasonable with one modification. When calculating the credit against the Annual PJM OATT LSE Recovery, the return on equity amounts used to calculate the incremental transmission investments shall be 9.7 percent, the Commission-approved ROE amount.

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[138] *Id.* at 28-29.

In conjunction with approving the PJM OATT LSE tracker, the Commission finds that the three-year stay-out provision in the Settlement is reasonable and should be accepted. In approving the tracker, the Commission addresses Kentucky Power's primary concern, raised in the last rate case and in this case, that an increase in major expenses not directly under Kentucky Power's control would result in more frequent rate cases.

Regarding proposed transmission projects at PJM, the Commission expects Kentucky Power to work through the PJM stakeholder process to protect its customer interests.

2. FAC Purchased Power Limitations.

Kentucky Power proposed to track, on a monthly basis, the amount of purchased power costs excluded for recovery through the FAC over or above the base rate level using deferral accounting. The annual net over- or under-collection of these purchase power costs would be collected from or credited to customers through Tariff P.P.A.[139]

The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered through the monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis to the cost of Kentucky Power's highest cost unit or the theoretical peaking unit equivalent, and caps the FAC-recoverable purchase power expense at the cost ($/MWh) of the highest generating unit (Kentucky Power owned or peaking unit equivalent). Kentucky Power claims that, because it relies on factors outside of its control, the FAC Purchase Power Limitation and the peaking unit equivalent calculation promote variability and volatility.

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[139] *Id.* at 29.

The Commission is not convinced that this issue requires special ratemaking treatment. The Commission has long held that any purchased power costs not recoverable through the FAC are eligible for recovery through base rates. The Commission finds Kentucky Power's proposal to include an estimated amount of FAC Purchased Power Limitation Expense in base rates, and to subsequently true up that amount through Tariff P.P.A., is unreasonable, and therefore should be denied. The Commission notes that Kentucky Power filed this case using a historic test period. The Commission will allow recovery of the test year amount of purchased power reasonably incurred, but excluded from the FAC. To the extent that Kentucky Power incurs any expense due to purchased power that is appropriately incurred after the test year, but excluded from the FAC, it can file a base rate case seeking recovery of those expenses. For the foregoing reasons, adjustments W26 and W27, which total $4,032,786, are unreasonable and should be removed from the revenue requirement.

3. Peaking Unit Equivalent Calculation

Kentucky Power proposed to change the methodology for calculating the peaking unit equivalent ("PUE") used in determining the FAC Purchased Power Limitation. In its Application, Kentucky Power proposes to include the cost of firm gas service as an expense in the calculation of its PUE. Kentucky Power stated that since the hypothetical combustion turbine ("CT") could be dispatched any day of the year, it requires firm gas service. The Commission disagrees. While firm gas service would certainly allow the CT to be dispatched any day of the year, the Commission is unaware of any jurisdictional utility utilizing firm gas service for a CT. Because CTs typically operate at low capacity factors and are primarily utilized during the summer peaking months, when pipeline capacity would typically not be constrained, the Commission finds the inclusion of firm gas service in the calculation of the PUE to be unreasonable, and therefore, this change in the PUE calculation should be denied. Kentucky Power's proposal to include startup costs and variable O&M expense is reasonable and should be approved.

4. Gains and Losses from Incidental Gas Sales.

Kentucky Power proposed to recover gains and losses from incidental sales of natural gas through Tariff P.P.A. Kentucky Power nominates Big Sandy Unit 1 in the PJM day-ahead electric power market based in part on the price of natural gas purchased for delivery the next day. If the Big Sandy Unit 1 Day Ahead nomination price is higher than the PJM electric power market clearing price, Big Sandy Unit 1 is not selected to run in the Real Time Market. In such a case, the natural gas purchased must either be stored by Columbia Gas or be sold. Kentucky Power stated that in August, September, and November of 2016, there were days that it was required to sell natural gas that had been purchased for delivery because Big Sandy Unit 1 was not selected by PJM to run.[140]

In Case No. 2014-00078, Duke Energy Kentucky ("Duke Energy") proposed similar treatment of gains and losses it experienced in January and February of 2014 from incidental sales of natural gas.[141] Duke Energy amended its request to apply to similar losses or gains occurring in the future. The Commission approved the treatment of the January and February 2014 gains and losses. However, the Commission found

[140] Application, Direct Testimony of John A. Rogness at 26-27

[141] Case No. 2014-00078, *An Investigation of Duke Energy Kentucky, Inc.'s Accounting Sale of Natural Gas Not Used in Its Combustion Turbines* (Ky. PSC Nov. 25, 2014).

Duke Energy's proposal to apply such treatment to similar losses or gains in the future to be overly broad and did not approve such treatment, finding that such gains and losses should be investigated on a case-by-case basis.

In this case, the Commission finds, as it did in Case No. 2014-00078, that gains and losses from the incidental sale of natural gas should be investigated on a case-by-case basis. If such gains or losses occur in the future, Kentucky Power should notify the Commission so those matters may be addressed in a formal proceeding. For purposes of this case, the Commission finds that the gain on the incidental sale of natural gas of $13,982 should be utilized to reduce Kentucky Power's revenue requirement.

Tariff K-12 School

In its Application, Kentucky Power proposed to discontinue the pilot Tariff K-12 School under which public schools in Kentucky Power's service territory took service under discounted rates. Kentucky Power stated that its load research and class cost of service study demonstrated that Tariff K-12 School customers would be better off in the Tariff L.G.S. customer class than they were previously a part of prior to the pilot Tariff K-12.

Tariff Pilot K-12 School was approved as part of the settlement agreement in Case No. 2014-00396. In Case No. 2014-00396, KSBA argued, as it does in this proceeding, that public school load characteristics were sufficiently unique to justify a distinct rate class for K-12 schools. Because school load data did not exist, Kentucky Power agreed to establish a pilot tariff with load research meters at 30 K-12 schools.

Kentucky Power further agreed to evaluate whether to continue Tariff K-12 School in its next base rate case using the load research data.

Tariff K-12 School rates were designed to produce an annual revenue requirement that was $500,000 less than would be produced under the L.G.S. rates from customers eligible to take service under Tariff K-12 School.[142] Tariff L.G.S. and Tariff M.G.S. customers rates were designed to include the $500,000 subsidy to Tariff K-12 Schools.[143]

Under the Settlement, Tariff K-12 School would cease to be a pilot, and would continue as a separate rate class. The tariff would be available to all K-12 schools, public and private, in Kentucky Power's service territory with normal maximum demands greater than 100 kW. Tariff K-12 School rates continue to be designed with a $500,000 subsidy absorbed by Tariff L.G.S. customers.

In its Settlement Testimony, KCUC asserted that the Settlement is unfair and unreasonable because L.G.S. customers had to absorb the subsidy to provide a $500,000 benefit for Tariff K-12 School customers, in addition to a significant inter-class subsidy burden as part of the overall rate structure.[144] KCUC stated that it did not object to the $500,000 discount to Tariff K-12 School customers, but instead objected that the discount is funded by L.G.S. customers, and not spread out among all customer classes. As a remedy, KCUC proposed that, if the Commission reduced the revenue requirement, that the first $500,000 of any reduction be applied first to reduce the revenue requirement of the L.G.S. class.

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[142] Case No. 2014-00396, Final Order, at 19.

[143] *Id.*

The Commission finds that load research data collected and analyzed by Kentucky Power demonstrates that a separate, discounted K-12 schools tariff is not justified and that public school usage characteristics do not support the discounted rates paid by Tariff K-12 School customers relative to the L.G.S. class. The Commission finds that it is unreasonable to continue Tariff K-12 School, and therefore rejects this portion of the Settlement.

Green Pricing Option Rider/Renewable Power Option Rider

Kentucky Power proposed to revise its Green Pricing Option Rider to expand the categories of renewable energy credits available, to allow participating customers to purchase their full requirements from renewable energy generators, and to change the name of the rider to the Renewable Power Option Rider ("Rider R.P.O"). The Commission finds that the Rider R.P.O. provision in the Settlement is reasonable and should be approved.

Tariff C.A.T.V.

In its Application, Kentucky Power proposed to increase Tariff C.A.T.V. rates for pole attachments on a two-user pole from $7.21 per year to $11.97 per year, and for pole attachments on a three-user pole from $4.47 per year to $7.52 per year. In the Settlement, Kentucky Power and the Settling Intervenors agreed to a rate of $10.82 per year for attachments on a two-user pole, and $6.71 per year for attachments on a three-user pole.

The Commission finds that the rates for Tariff C.A.T.V. as set forth in the Settlement are reasonable and should be approved.

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[144] Higgins Settlement Testimony at 2.

Temporary Service Tariff

In its Application, Kentucky Power proposed to revise its Temporary Service Tariff ("Tariff T.S.") to limit service provided under Tariff T.S. to ensure that customers do not continue to take service under Tariff T.S. even after construction is complete and the facility is occupied. The Commission finds these changes to be reasonable and that they should be approved.

Optional Residential Demand Charge Tariff

Kentucky Power proposed a new optional residential rate schedule ("Tariff R.S.D.") that will be available to up to 1,000 residential customers. The rate structure will consist of a monthly service charge, on-peak and off-peak kWh energy charges, and an on-peak kW demand charge. Kentucky Power stated that the goal of Tariff R.S.D. is to send targeted price signals that will reward customers for shifting usage away from the peak time periods that cause Kentucky Power to incur higher costs. Kentucky Power also stated that certain electric heating customers may benefit from Tariff R.S.D. due to their potentially higher load factor usage characteristics, and that the rate design is revenue neutral to the standard residential tariff.[145]

The Commission finds the proposed Tariff R.S.D. to be reasonable, that it should be approved, and that the rates included in Appendix C of this Order should be approved.

Tariff C.S.-Coal, Tariff C.S.-I.R.P. and Tariff E.D.R.

The Settlement extends through December 31, 2018, Tariff C.S.-Coal and the amendments to Tariff C.S.-I.R.P. and Tariff E.D.R., which were due to expire December

[145] Vaughan Direct Testimony at 19

31, 2017. The Commission finds the extension of the tariffs reasonable and that they should be approved. Any financial loss incurred in connection with these tariffs will be deferred for review and recovery in Kentucky Power's next base rate proceeding.

ENVIRONMENTAL COMPLIANCE PLAN

In its Application, Kentucky Power requested Commission approval of an amended environmental Compliance Plan ("2017 Plan") and an amended Environmental Surcharge tariff ("Tariff E.S.").

The 2017 Environmental Compliance Plan

The 2017 Plan includes previously approved projects and two new projects, Project 19 and Project 20. The 20 projects included in the 2017 Plan are listed in Appendix D to this Order.

Project 19 will install SCR technology at Rockport Unit 1 ("Rockport Unit 1 SCR Project"). The Rockport Unit 1 SCR project will reduce the plant's nitrogen oxide emissions, and is required under terms of a 2007 Consent Decree ("Consent Decree") among several AEP entities including Kentucky Power and I&M, and the Environmental Protection Agency and several environmental plaintiffs.

Project 20 seeks to include a return on inventories for consumables used in conjunction with approved projects through Tariff E.S. Kentucky Power currently recovers the cost of the consumption of consumables through Tariff E.S. The return on consumable inventories is currently part of the general rate base. Kentucky Power proposed that the return on consumable inventories be recovered through Tariff E.S. to align that cost with the cost recovery of items consumed.

Kentucky Power stated that the pollution control projects included in the 2017 Plan amendment are necessary to comply with the Federal Clean Air Act ("CAA") and other federal, state, and local regulations that apply to coal combustion wastes and by-products from facilities utilized for the production of energy from coal. Kentucky Power asserted that the costs associated with its 2017 Plan are reasonable, and that the projects are a reasonable and cost-effective means to comply with environmental requirements.

The Attorney General argued that Kentucky Power should not be permitted to recover the cost of the Rockport Unit 1 SCR Project.[146] The Attorney General asserted that Kentucky Power's customers have been paying increasing amounts for environmental costs resulting from the Consent Decree because AEP voluntarily made environmental upgrades at generating stations, including the Rockport generating units, that were not identified in the original EPA litigation that led to the Consent Decree. Because Rockport was not part of the original litigation, the Attorney General asserts Kentucky Power should not recover the costs for the Rockport Unit 1 SCR project from its ratepayers.

In rebuttal, Kentucky Power stated that the decision to include Rockport in the Consent Decree settlement was a way to remove the significant risk of additional litigation at those units not named in any pending complaints, as well as to provide a more favorable outcome than would be expected on an individual basis.[147] Kentucky Power further stated that the Consent Decree provided certainty regarding the timing of

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[146] Smith Testimony at 59.
[147] Rebuttal Testimony of John McManus at 3.

additional control installations across the AEP fleet. At the time of the settlement, Kentucky Power was still participating in the AEP Pool, which meant that the outcome of litigation involving all units across the AEP fleet contributing to the pool was in the best interest of Kentucky Power and its customers.

The Settlement was silent on the 2017 Environmental Compliance Plan.

The Commission finds that the 2017 Plan is reasonable as set forth in the Application and should be approved.

ENVIRONMENTAL SURCHARGE TARIFF MODIFICATIONS

Kentucky Power updated its Tariff E.S. to reflect the changes proposed in its Application and the Settlement. Kentucky Power updated the list of projects in the tariff to match the projects included in the 2017 Plan as noted previously in this Order. Kentucky Power updated Tariff ES to reflect the rate of return included in the Settlement to this case. Kentucky Power also updated the tariff to reflect the new monthly base environmental costs based on that rate of return. Kentucky Power determined the annual base revenue requirement level for environmental cost recovery to be $47,513,461.[148] The Commission has determined that the correct annual base revenue requirement is $44,379,316, which reflects the Commission authorized return on equity, capital structure changes, reduction of the federal corporate income tax rate from 35 percent to 21 percent and the depreciation rates set forth in Exhibit 5 of the

[148] In the Tariff E.S. filed December 1, 2017, Kentucky Power reflected an annual base revenue requirement of $47,811,215. Kentucky Power updated this amount to $47,513,461 to reflect the depreciation rates included in Exhibit 5 to the Settlement Agreement. See Response to Commission Staff's Post-Hearing Request for Information ("Staff's Post-Hearing Request"), Item 20 attachment KPCO_R_KPSC_PH_20_Attachment1.xls.

Settlement.[149] Kentucky Power shall file a revised Tariff ES to reflect the Commission authorized return on equity and capitalization discussed in this Order, and the annual base revenue requirement as shown on Appendix E attached to this order. Per the settlement agreement in Case No. 2012-00578,[150] all costs associated with the Mitchell FGD equipment are excluded from base rates and therefore are not included in the base revenue requirement noted above, but will be included as part of the current period environmental revenue requirement. The Commission finds that Tariff E.S. as discussed and modified in this Order should become effective for service rendered on and after the date of this Order.

<u>Costs Associated with the 2015 Plan</u>

Tariff E.S. revenue requirement is determined by comparing the base period revenue requirement with the current period revenue requirement. Kentucky Power proposed to incorporate the costs associated with the 2017 Plan into the existing surcharge mechanism used for previous compliance plans. Kentucky Power identified the environmental compliance costs for the 2017 Plan projects, which Kentucky Power proposed to recover through its environmental surcharge. Kentucky Power proposed to apply a gross-up factor to environmental expenses to account for uncollectible accounts and the Commission assessment fee. The factor will be applied to the incremental change in operating, maintenance, and other expenses from the base period. The

[149] Response to Staff's Post-Hearing Request, Item 20.

[150] Case No. 2012-00578, *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* (Ky. PSC Oct. 7, 2013).

costs identified by Kentucky Power are eligible for surcharge recovery if they are shown to be reasonable and cost-effective for complying with the environmental requirements specified in KRS 278.183. The Commission finds that the costs identified for the 2017 Plan projects have been shown to be reasonable and cost-effective for environmental compliance. Thus, they are reasonable, and should be approved for recovery through Kentucky Power's environmental surcharge.

Qualifying Costs

As stated previously, the qualifying costs included in Kentucky Power's annual baseline level for environmental cost recovery under the tariff shall be $44,379,316. The qualifying costs included in the current period revenue requirement will reflect the Commission-approved environmental projects from Kentucky Power's 1997, 2005, 2007, 2015 and 2017 Plans. Per the settlement agreement in Case No 2012-00578, all costs associated with Mitchell Units 1 and 2 FGD equipment have been excluded from base rates and the environmental baseline level and shall be recovered exclusively through Tariff E.S. Should Kentucky Power desire to include other environmental projects in the future, it will have to apply for an amendment to its approved compliance plans.

Rate of Return

Paragraph 8(a) of the Settlement authorizes Kentucky Power to use a 9.75 percent ROE to be utilized in Tariff E.S. to determine the WACC for non-Rockport environmental projects. However as previously noted, the Commission has authorized a 9.70 percent ROE that should be used for all non-Rockport environmental projects.

Kentucky Power's ROE for environmental projects at the Rockport Plant is 12.16 percent as established by the FERC-approved Rockport Unit Power Agreement.

Capitalization and Gross Revenue Conversion Factor

Paragraph 3(c) and Exhibit 6 of the Settlement provide that Kentucky Power shall utilize a WACC of 6.48 percent and a gross revenue conversion factor ("GRCF") of 1.6433 to determine a rate of return of 9.11 percent to be used in the monthly environmental surcharge filings. As a result of the reduction of the federal corporate tax rate from 35 percent to 21 percent, the Commission has determined that Kentucky Power should use a GRCF of 1.352116. Because of the change in the authorized ROE, capitalization, and the GRCF, the WACC to be used for non-Rockport environmental projects is 6.44 percent. Utilizing a WACC of 6.44 percent and a GRCF produces a rate of return of 7.88 percent to be used in the monthly environmental surcharge filings. The WACC and GRCF shall remain constant until the Commission sets base rates in Kentucky Power's next base rate case proceeding.

Surcharge Formulas

The inclusion of the 2017 Plan into Kentucky Power's existing surcharge mechanism will not result in changes to the surcharge formulas. The costs associated with the Mitchell FGD will be excluded from base rates and the base rate revenue requirement of the environmental surcharge at least until June 30, 2020, but will be included in the current period revenue requirement for the environmental surcharge. The Commission finds that the formulas used to determine the environmental surcharge revenue requirement as proposed by Kentucky Power should be approved.

Surcharge Allocation

The retail share of the revenue requirement will be allocated between residential and non-residential customers based upon their respective total revenue during the previous calendar year. The environmental surcharge will be implemented as a percentage of total revenues for the residential class and as a percentage of non-fuel revenues for all other customers.

Monthly Reporting Forms

The inclusion of the 2017 Plan into the existing surcharge mechanism will require modifications to the monthly environmental surcharge reporting forms. Kentucky Power provided its proposed revised forms to be used in the monthly environmental reports. The revised forms include the changes necessary to reflect the proposed 2017 Plan, as well as changes necessitated by the application of a gross-up factor to the incremental operating, maintenance and other expenses. The Commission finds that Kentucky Power's proposed monthly environmental surcharge reporting forms as revised should be approved.

FINDINGS ON SETTLEMENT AGREEMENT

Based upon a review of all the provisions in the Settlement, an examination of the entire record, and being otherwise sufficiently advised, the Commission finds that the provisions of the Settlement are in the public interest and should be approved, subject to the modifications as discussed in this Order. Our approval of the Settlement as modified is based solely on its reasonableness and does not constitute precedent on any issue except as specifically provided for in this Order.

OTHER ISSUES

Vegetation Management

Kentucky Power's current Vegetation Management Plan ("2015 Vegetation Management Plan") was modified from its 2010 Vegetation Management Plan in Kentucky Power's last rate case, Case No. 2014-00396. In Case No. 2014-00396, it was determined that funding for the 2010 Vegetation Management Plan, which was scheduled to move to a four-year cycle within seven years of initial circuit clearing, needed modification. However, the work required to transition to a four-year cycle was significantly greater than initially estimated, and Kentucky Power could not wait until all circuits had an initial clearing ("Task 1") to begin re-clearing the circuits. Thus, the modification was approved allowing the continuation of Task 1 and a simultaneous undertaking of interim re-clearing ("Task 2"). Under this schedule, Task 1 would be completed by December 31, 2018, Task 2 would be completed by June 30, 2019, and on July 1, 2019, Kentucky Power's entire distribution system would commence to be re-cleared on a five-year cycle ("Task 3"), rather than a four-year cycle. Funding was approved for the 2015 Vegetation Management Plan, as well as a provision requiring Kentucky Power to obtain Commission approval prior to modifying its annual projected vegetation management spending on both an aggregate and a district basis if the change is more than 10 percent of the budget.

Kentucky Power is on pace to exceed the December 31, 2018 target for Task 1, and expects to complete Task 1 circuit clearing in the first quarter of 2018. In addition, Task 2 circuit re-clearing is expected to be completed by December 31, 2018, six months sooner than projected. To date, Kentucky Power has exceeded targets on budget as total expenditures are 101 percent of target level.[151] Reliability has increased

[151] Application, Direct Testimony of Everett G. Phillips ("Phillips Testimony") at 35.

and Kentucky Power customers have seen a 60 percent decrease in interruptions related to rights-of-way trees and vegetation.[152] Task 3 is estimated to begin in January 2019.

Embedded in Kentucky Power's current base rates are annual vegetation management O&M expenses of $27.661 million. Due to early completion of Tasks 1 and 2, Kentucky Power estimates a reduction of O&M expenses related to Tasks 1 and 2 from $27.661 million in 2017 to $21.639 million 2018. According to the 2015 Vegetation Management Plan, at the start of Task 3, O&M expenses are projected to decrease, resulting in a decrease of O&M expenses of $11.780 million. However, Kentucky Power has determined that the estimates of the annual O&M expenditures for Task 3 as estimated in the 2015 Vegetation Management Plan are undervalued and need to be increased.[153] Due to the re-clearing in Task 2, Kentucky Power now has a better grasp on regrowth, the effect of higher-than-average rainfall, and growing customer demand to remove tree debris, and proposes to increase the annual O&M expenses for Task 3. This re-estimation calculates costs for Task 3 to increase from the original $15.880 million to $21.284 million in 2019, and $21.473 in 2020.[154] Kentucky Power proposes the amount of vegetation management O&M expenses to be recovered through base rates for the instant case to be equal to the average of the revised estimated annual vegetation management plan O&M spending over 2018-2020, or $21.465 million.[155]

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[152] *Id* at 40.

[153] *Id.*

[154] *Id.* at 46

Kentucky Power also proposes two changes to its current vegetation management reporting requirements. First, Kentucky Power proposes to modify the pre-approval requirement for deviation of 10 or more percent from projected annual vegetation management O&M expenditures to eliminate the district-specific threshold and retain only the requirement for pre-approval if overall Kentucky Power vegetation management expenditures deviate more than 10 percent. Second, Kentucky Power proposes to manage its vegetation work and expenditures on a calendar year basis, as opposed to managing its vegetation work on a fiscal year and expenditures on a calendar year. Kentucky Power stresses that neither modification will change their overall vegetation management obligation, but provides for more flexibility to manage its obligations.[156]

The 2015 Vegetation Management Plan included a one-way balancing account. In this balancing account, any annual shortfall or excess in vegetation management O&M expenditures that is over the amount in base rates is added to or subtracted from future expenditures over four years. At the end of the four-year period, Kentucky Power will record a cumulative shortfall as a regulatory liability that will either be refunded to the customers or used to reduce the revenue requirement in its next filed base-rate case. If Kentucky Power has overspent on a cumulative basis during the four-year period, it will not seek recovery of such costs in a future base-rate proceeding. As of the end of November 2017, Kentucky Power testified that cumulative expenditures were slightly over the budgeted amount.[157]

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[155] Application, Section V, Exhibit 2, page 59.

[156] *Id.* at 43.

The Commission finds that the one-way balancing adjustment should be continued; however due to the change in the annual revenue requirement as noted in the Application, it should be adjusted accordingly. All expenses will be recorded against the annual budget. The annual shortfall or excess will be applied to the balance account. Through 2023, or until Kentucky Power's next base rate application, whichever occurs first, the expenditures will be balanced against the annual projected expenditures as found in the Application.[158]

The Commission approves the proposed modifications allowing Kentucky Power to request Commission approval for any spending deviation greater than 10 percent on an aggregate level as opposed to a district level. The Commission also approves Kentucky Power's request to manage its vegetation management program on a calendar year basis to coincide with the budgetary year. The Commission notes that Kentucky Power has exceeded the goals of the 2015 Vegetation Management Plan resulting in a reduction of O&M expenses 24 months earlier than estimated. The Commission approves Kentucky Power's proposed revenue requirement of $21.465 million. All other provisions of the 2015 Vegetative Management Plan are to remain unchanged.

The Commission will continue to review closely the vegetation management annual work plans and expenditures filed by Kentucky Power. In addition, the Commission will monitor the progress of the five-year maintenance cycle.

Bill Redesign

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[157] Dec. 8, 2017 H.V.T. at 2:09:38.

[158] Phillips Testimony, Table 9 at 46.

On June 12, 2017, Kentucky Power filed an Application requesting approval to implement new bill formats that change the bill layout and composition, which is being implemented concurrently for all AEP operating companies, and to combine certain billing line items. That Application was docketed as Case No. 2017-00231.[159] By Order dated July 17, 2017, that case was consolidated into this proceeding. By further Order dated September 12, 2017, the Commission approved Kentucky Power's request to redesign the appearance of its bills, but stated that a decision on the proposed substantive changes to consolidate billing line items would be determined in the final Order in this proceeding.

Kentucky Power proposed to consolidate eight residential billing line items,[160] and seven commercial and industrial billing line items[161] into a single "Rate Billing" line item. Kentucky Power explained that customer satisfaction regarding billing correspondence was below the industry average according to a survey commissioned by Kentucky Power.[162] Kentucky Power asserted that its customers found the number of billing line

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[159] Case No. 2017-00231, *Electronic Application of Kentucky Power Company for (1) Approval of Its Revised Terms and conditions of Service Implementing New Bill Formats; (2) An Order Granting All other Required Approvals and Relief* (filed June 12, 2017).

[160] The residential billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Residential Home Energy Assistance Program Charge, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The residential charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, State Sales tax, and HomeServe Warranty.

[161] The commercial and industrial billing line items Kentucky Power proposes to consolidate into a single line items are Rate Billing, Kentucky Economic Development Surcharge, Capacity charge, Big Sandy 1 Operation Rider, Big Sandy Retirement Rider, Purchased Power Adjustment, and Green Pricing Option. The commercial and industrial charges that Kentucky Power proposes to continue to display as individual billing line items are the Fuel Adjustment Charge, Demand-Side Management Factor, Environmental Surcharge, School Tax, Franchise Fee, and State Sales tax.

[162] Case No. 2017-00231, Direct Testimony of Stephen L. Sharp, Jr. (filed June 12, 2017) at 2.

items were "unhelpful," made the bills "difficult to understand," and obscured the information customers most wanted to know, which was the total amount owed and payment due date.[163] Kentucky Power further asserted that customers requested that line items be consolidated in order to simplify the bills. Customers who want detailed billing information could contact a Kentucky Power customer service center.

In the Settlement, the Settling Intervenors agreed to Kentucky Power's proposed consolidation of billing line items.

Neither KCUC nor the Attorney General filed testimony in this proceeding regarding the consolidation of billing line items. However, in a motion filed in Case No. 2017-00231 before it was incorporated into this proceeding, the Attorney General argued that consolidating the billing line items would result in a lack of transparency that impeded customers' understanding of how rates and their bills are calculated.[164]

The Commission finds that Kentucky Power's proposed consolidation of billing line items is unreasonable and should be denied. The Commission concurs with the Attorney General that displaying discrete billing line items on customer bills promotes transparency and customer understanding of their billing amounts. Further, it is not reasonable to require customers to take additional steps in order to obtain a detailed accounting for their bills. This is especially so given that the billing line items that Kentucky Power wishes to consolidate represent charges in addition to the base rate charge for utility service.

<u>Analysis of Kentucky Power's Participation in PJM</u>

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[163] *Id.* at 3; *Id.* at Application, paragraph 11.

Kentucky Power currently elects to self-supply its PJM capacity requirements under the Fixed Resource Requirement ("FRR") alternative. As discussed in testimony at the hearing, AEP conducts regular evaluations to determine whether its operating companies in PJM should elect to participate in the Reliability Pricing Model ("RPM") capacity market, or to self-supply under FRR.[165]

The Commission finds that Kentucky Power should file an annual update of the FRR/RPM election analysis. The Commission recognizes that this information is deemed confidential during the AEP internal decision-making process. However, once PJM is notified of the election, the information becomes public and ceases to be confidential. Kentucky Power should file the annual update after the information becomes public.

Further, the Commission recognizes that Kentucky Power's interests may not be aligned with the interests of other AEP operating companies. The Commission is aware that PJM bills AEP based on a one-coincident peak methodology, and that AEP subsequently allocates those costs to its operating companies using a twelve-coincident peak methodology. The Commission finds that Kentucky Power should file an annual report with the supporting calculations used by AEP to allocate these costs.

Last, the Commission strongly encourages Kentucky Power to recognize that it must make a determination regarding its participation in PJM that aligns with the interests of Kentucky Power and its ratepayers.

<u>Reduction in Corporate Tax Rates</u>

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[164] Case No. 2017-00231, Attorney General's Motion to Consolidate Cases (filed July 13, 2017) paragraphs 4-5.

[165] Dec. 7, 2017 H.V.T. at 10:43:18, and Kentucky Power Exhibit 9.

Effective January 1, 2018, the federal corporate income tax rate was reduced from 35 percent to 21 percent. Consistent with Kentucky Power's revised gross-up factor calculation in certain riders, the Commission finds that it is reasonable to utilize the 21 percent corporate income tax rate in the gross-up factor calculation. The Commission will address the impact of the recently enacted tax cuts on the excess ADIT and the rates of all investor-owned utilities, including Kentucky Power, on a prospective basis in pending cases that were opened on December 27, 2017.[166]

Based on the evidence of record and the findings contained herein, HEREBY ORDERS that:

1. The rates and charges proposed by Kentucky Power are denied.

2. The provisions in the Settlement, as set forth in Appendix A to this Order, are approved, subject to the modifications and deletions set forth in this Order.

3. The rates and charges for Kentucky Power, as set forth in Appendix C to this Order, are the fair, just, and reasonable rates for Kentucky Power, and these rates are approved for service rendered on and after January 19, 2018.

4. Kentucky Power's request to deviate from 807 KAR 5:006, Section 14(2)(a) by limiting enrollment in its Equal Payment Plan to the months of April through December is granted.

5. Kentucky Power's proposed depreciation rates, with the exception of the changes proposed in the Settlement are approved.

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[166] Case No. 2017-00477, *Kentucky Industrial Utility Customers, Inc. v. Kentucky Utilities Company, Louisville Gas and Electric Company, Kentucky Power Company, and Duke Energy Kentucky, Inc.* (Ky PSC Dec. 27, 2017); Case No. 2017-00481, *An Investigation of the Impact of the Tax Cuts and Job Act on the Rates of Atmos Energy Corporation, Delta Natural Gas Company, Inc., Columbia Gas of Kentucky, Inc., Kentucky-American Water Company, and Water Service Corporation of Kentucky* (Ky. PSC Dec. 27, 2017).

6. The regulatory asset or liability account established by under- or over-recovery from the elimination of Tariff B.S.1.O.R. is approved for accounting purposes only.

7. The regulatory asset account established by the deferral of Rockport UPA expenses is approved for accounting purposes only.

8. Kentucky Power's 2017 Environmental Compliance Plan is approved.

9. Kentucky Power's environmental surcharge tariff is approved for service rendered on and after the date of this Order.

10. The base period and current period revenue requirements for the environmental surcharge shall be calculated as described in this Order.

11. The environmental reporting formats described in this Order shall be used for the monthly environmental surcharge filings. Previous reporting formats shall no longer be submitted.

12. The Commission approves the sample forms that were filed by Kentucky Power on January 3, 2018.

13. Within three months of the date of this Order, Kentucky Power shall identify and contact GS class customers whose average monthly demand is 25 kW or greater for the purpose of meeting to discuss the impact of the rate increase on their bills and analyze other available tariff options, such as time-of-day rates.

14. Within twelve months of the date of this Order, Kentucky Power shall file a report listing the names of each GS class customers whose average monthly demand is 25 kW or greater, and stating the date and method of contact with the customer, whether Kentucky Power has met with the customer, and the results of each meeting.

15. Kentucky Power's request to revise its billing format to consolidate billing line items, as set forth in the application, is denied.

16. Kentucky Power's Vegetation Management Plan, as set forth in the Application, is approved.

17. Kentucky Power's request to obtain Commission approval for any spending deviation from its Vegetation Management Plan greater than 10 percent on an aggregate level as opposed to a district level is approved.

18. Kentucky Power's request to manage its Vegetation Management Plan on a calendar year basis is approved.

19. Kentucky Power shall file an annual update of the FRR/RPM election analysis conducted by AEP and its operating companies within 30 days of notifying PJM of the election.

20. Kentucky Power shall file annually the supporting calculations for allocating PJM bills, which are based on a one-coincident peak methodology, AEP's operating companies using a twelve-coincident-peak methodology.

21. Within 20 days of the date of this Order, Kentucky Power shall, using the Commission's electronic Tariff Filing System, file its revised tariffs setting out the rates authorized herein and reflecting that they were approved pursuant to this Order.

By the Commission

ENTERED

JAN 18 2018

KENTUCKY PUBLIC
SERVICE COMMISSION

ATTEST:

Gwen R. Pinson

Executive Director

Case No. 2017-00179

APPENDIX A

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 1 8 2018

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets Or Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)	Case No. 2017-00179

SETTLEMENT AGREEMENT

This Settlement Agreement, made and entered into this 22nd day of November, 2017, by and among Kentucky Power Company ("Kentucky Power" or "Company"); Kentucky Industrial Utility Customers, Inc. ("KIUC"); Kentucky School Boards Association ("KSBA"); Kentucky League of Cities ("KLC"); Wal-Mart Stores East, LP and Sam's East, Inc. ("Wal-Mart"); and Kentucky Cable Telecommunications Association ("KCTA"); (collectively Kentucky Power, KIUC, KSBA, KLC, Wal-Mart, and KCTA, are "Signatory Parties").

RECITALS

1. On June 28, 2017 Kentucky Power filed an application pursuant to KRS 278.190, KRS 278.183, and the rules and regulations of the Public Service Commission of Kentucky ("Commission"), seeking an annual increase in retail electric rates and charges totaling $69,575,934, seeking approval of its 2017 Environmental Compliance Plan, an order approving accounting practices to establish regulatory assets or liabilities, and further seeking authority to implement or amend certain tariffs ("June 2017 Application").

2. On August 8, 2017, Kentucky Power supplemented its filing to reflect the impact of subsequent refinancing activities on the Company's Application ("August 2017 Refinancing Update"). The refinancing activities reduced the Company's requested annual increase in retail electric rates and charges from $69,575,934 to $60,397,438.

3. KIUC, KSBA, KLC, Wal-Mart, and KCTA filed motions for full intervention in Case No. 2017-00179. The Commission granted the intervention motions. Collectively KIUC, KSBA, KLC, Wal-Mart, and KCTA are referred to in this Settlement Agreement as the "Settling Intervenors."

4. The Attorney General of the Commonwealth of Kentucky ("Attorney General") and Kentucky Commercial Utility Customers, Inc. ("KCUC") also filed motions to intervene. The Attorney General and KCUC, who are not parties to this agreement, were granted leave to intervene.

5. Certain of the Settling Intervenors, KCUC, and the Attorney General filed written testimony in Case No. 2017-00179 raising issues regarding Kentucky Power's Rate Application.

6. Kentucky Power, KCUC, the Attorney General, and the Settling Intervenors have had a full opportunity for discovery, including the filing of written data requests and responses.

7. Kentucky Power offered the Settling Intervenors, KCUC, and the Attorney General, along with Commission Staff, the opportunity to meet and review the issues presented by Kentucky Power's application in this proceeding and for purposes of settlement.

8. The Signatory Parties execute this Settlement Agreement for purposes of submitting it to the Kentucky Public Service Commission for approval pursuant to KRS 278.190 and KRS 278.183 and for further approval by the Commission of the rate increase, rate structure, and tariffs as described herein.

9. The Signatory Parties believe that this Settlement Agreement provides for fair, just, and reasonable rates.

NOW, THEREFORE, for and in consideration of the mutual promises set forth above, and the agreements and covenants set forth herein, Kentucky Power and the Settling Intervenors hereby agree as follows:

AGREEMENT

1. Kentucky Power's Application

(a) Except as modified in this Settlement Agreement, Kentucky Power's June 2017 Application as updated by the August 2017 Refinancing Update is approved.

2. Revenue Requirement

(a) Effective for service rendered on or after January 19, 2018, Kentucky Power shall implement a base rate adjustment sufficient to generate additional annual retail revenues of $31,780,734. This annual retail revenue amount represents a $28,616,704 million reduction from the $60,397,438 sought in the Company's August 2017 Refinancing Update.

(b) The $28,616,704 million reduction was the result of the following adjustments to the Company's request in the June 2017 Rate Application as modified in the August 2017 Refinancing Update:

Adjustment	**Reduction in Revenue Requirement ($Millions)**
Defer a portion of Rockport UPA non-fuel, non-environmental expenses	15.0
Increase revenues to Apply Weather Normalization to Commercial Sales Net of Variable O&M	0.40
Reduce Incentive Compensation	3.15
Reduce Amortization Expense to Recalibrate Storm Damage Amortization	1.22

Reduce Depreciation Expense by Extending Service Life of BS1 to 20 years	2.84
Reduce Depreciation Expense by Removing Terminal Net Salvage for BSU1	0.37
Reduce Depreciation Expense by Removing Terminal Net Salvage for Mitchell	0.57
Increase Short Term Debt to 1% and Set Debt Rate at 1.25%	0.36
Change in Return on Equity from 10.31% to 9.75%	4.70
Total Adjustments	**28.6**

(c) Kentucky Power agrees to allocate the $31,780,734 in additional annual revenue as illustrated on **EXHIBIT 1.** The Company will design rates and tariffs consistent with this allocation of additional revenue.

(i) As part of the Commission's consideration of the reasonableness of this Settlement Agreement, the tariffs designed in accordance with this subparagraph shall be filed with the Commission and served on counsel for all parties to this case no later than December 1, 2017.

(ii) Within ten days of the entry of the Commission's Order approving without modification this Settlement Agreement and the rates thereunder, Kentucky Power shall file with the Commission signed copies of the tariffs in conformity with 807 KAR 5:011.

3. Rockport UPA Expense Deferral

(a) Kentucky Power is a party to a FERC-approved Unit Power Agreement with AEP Generating Company for capacity and energy produced at the Rockport Plant ("Rockport UPA"). The Rockport UPA expires on December 8, 2022.

(b) Kentucky Power will defer a total of $50 million in non-fuel, non-environmental Rockport UPA Expense for later recovery as follows:

(i) Kentucky Power will defer $15M annually of Rockport UPA Expense in 2018 and 2019 for later recovery.

(ii) Kentucky Power will defer \$10M of Rockport UPA Expense in 2020 for later recovery.

(iii) Kentucky Power will defer \$5M annually of Rockport UPA Expense in years 2021 and 2022 for later recovery.

(c) The Rockport UPA Expense of \$50 million described in Paragraph 3(b) above will be deferred into a regulatory asset ("the Rockport Deferral Regulatory Asset") and will be subject to carrying charges based on a weighted average cost of capital ("WACC") of 9.11%[1] until the Regulatory Asset is fully recovered. From January 1, 2018 through December 8, 2022, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset principal balance net of accumulated deferred income taxes ("ADIT"). From December 9, 2022 until the Rockport Deferral Regulatory Asset is fully recovered, the WACC will be applied to the monthly Rockport Deferral Regulatory Asset balance including deferred carrying charges net of ADIT. The Rockport Deferral Regulatory Asset shall be recovered on a levelized basis through the demand component of Tariff P.P.A. and amortized over five years beginning on December 9, 2022. Kentucky Power estimates that the regulatory asset balance will total approximately \$59 million on December 8, 2022.

(d) Additional expenses reflecting the declining deferral amount in years 2020 through 2022 will be recovered through the demand component of Tariff P.P.A. as follows:

(i) Kentucky Power will recover \$5 million through Tariff P.P.A. in 2020

(ii) Kentucky Power will recover \$10 million through Tariff P.P.A. in 2021

[1] 6.48% grossed up for applicable State and Federal taxes, uncollectible accounts expense, and the KPSC maintenance fee

(iii) Kentucky Power will recover $10 million through Tariff P.P.A. in 2022, prorated through December 8, 2022.

(e) The Signatory Parties acknowledge that the Company's decision whether to seek Commission approval to extend the Rockport UPA will be made at a later date. Whether or not the Company seeks to extend the Rockport UPA, beginning December 9, 2022, the Capacity Charge recovered through Tariff C.C., approved in Case No. 2004-00420, will end. Any final over- or under-recovery balance will be included in the subsequent calculation of the purchase power adjustment under Tariff P.P.A. In the event that Kentucky Power elects not to extend the Rockport UPA, it will experience a reduction in Rockport UPA fixed costs ("Rockport Fixed Costs Savings").

(f) If Kentucky Power elects not to extend the Rockport UPA, it will, beginning December 9, 2022, credit the Rockport Fixed Cost Savings through the demand component of Tariff P.P.A. until new base rates are set. However, for 2023 only, the Rockport Fixed Cost Savings credit will be offset by the amount, if any, necessary for the Company to earn its Kentucky Commission-authorized return on equity (ROE) for 2023 ("Rockport Offset"). An example of the calculation of the Rockport Offset is included as **EXHIBIT 2**.

(g) For the purposes of implementing the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above, the following definitions apply:

(i) "Rockport Fixed Costs Savings" shall mean the annual amount of non-fuel, non-environmental Rockport UPA expense included in base rates for rates effective in November 2022.

(ii) "Estimated Rockport Offset" shall mean the amount of additional annual revenue the Company estimates would be necessary for it to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings.

(iii) "Actual Rockport Offset" shall mean the amount of additional annual revenue that would have been necessary for the Company to earn the Commission-authorized return on equity for 2023 considering the termination of the Rockport UPA and the Rockport Fixed Cost Savings. The Company shall calculate the Actual Rockport Offset using a comparison of the per books return on equity for 2023 to the Commission-approved return on equity. The Actual Rockport Offset cannot exceed the Rockport Fixed Costs Savings.

(iv) "Rockport Offset True-Up" shall mean the difference between the Estimated Rockport Offset and the Actual Rockport Offset.

(h) The Company shall implement the Rockport Fixed Costs Savings credit described in Paragraph 3(f) above as follows:

(i) By November 15, 2022, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective December 9, 2022. This filing shall reflect the impact of the Rockport Fixed Cost Savings and the Estimated Rockport Offset on the purchase power adjustment factor. This filing shall also reflect the commencement of recovery of the Rockport Deferral Regulatory Asset.

(ii) The Company shall make its normal August 15, 2023 Tariff P.P.A. filing for rates effective in October 2023. The Rockport Fixed Cost Savings and the Estimated Rockport Offset will continue to be factored into the calculation of the purchase power adjustment factor through the end of 2023. Beginning in January 2024, the Estimated Rockport Offset will not be factored into the calculation of the purchase power adjustment factor.

(iii) By February 1, 2024, the Company shall file an updated purchase power adjustment factor under Tariff P.P.A. for rates effective March 1, 2024. This filing shall only reflect the impact of the Rockport Offset True-Up on the purchase power adjustment factor. The purchase power adjustment factor shall be established to recover or credit the Rockport Offset True-Up amount in three months.

(iv) Beginning with the August 15, 2024 Tariff P.P.A. filing, the Company will incorporate the Rockport Fixed Cost Savings in its annual calculation of the purchase power adjustment factor.

4. <u>PJM OATT LSE Expense Recovery</u>

(a) As described in the testimony of Company Witness Vaughan, Kentucky Power has included an adjusted test year amount of net PJM OATT LSE charges and credits in base rates. Kentucky Power will track, on a monthly basis, the amount of OATT LSE charges and credits above or below the base rate level using deferral accounting. Kentucky Power will recover and collect 80% of the annual over or under collection of PJM OATT LSE charges, as compared to the annual amount included in base rates, ("Annual PJM OATT LSE Recovery") through the operation of Tariff P.P.A.

(b) Kentucky Power will credit against the Annual PJM OATT LSE Recovery 100% of the difference between the return on its incremental transmission investments calculated using the FERC-approved PJM OATT return on equity and the return on its incremental transmission investments calculated using the 9.75% return on equity provided for in this settlement (the "Transmission Return Difference"). Kentucky Power shall calculate the Transmission Return Difference as shown in **EXHIBIT 3**.

(c) These changes to Tariff P.P.A. to allow for the Annual PJM OATT LSE Recovery will terminate on the effective date when base rates are reset in the next base rate proceeding unless otherwise specifically extended by the Commission. Nothing in this Paragraph 4(c) prohibits Kentucky Power or any other Signatory Party from taking any position regarding the extension of the Annual PJM OATT LSE Recovery mechanism or any other treatment of the Company's PJM OATT LSE expenses.

5. Rate Case Stay Out

(a) Kentucky Power will not file an application for a general adjustment of base rates for rates that would be effective prior to the first day of the January 2021 billing cycle. This rate case "stay out" is expressly conditioned on Commission approval of this Settlement Agreement without modification including the recovery of the Rockport Deferral Regulatory Asset as described in Section 3 above and the incremental PJM OATT LSE expense through Tariff P.P.A. as described in Section 4 above.

(b) This stay out will not apply if a change in law occurs that will result in a material adverse effect on the Company's financial condition.

(c) Nothing in this stay out provision should be interpreted as prohibiting the Commission from altering the Company's rates upon its own investigation, or upon complaint, including to reflect changes in the tax code, including the federal corporate income tax rate, depreciation provisions, or upon a request by the Company to seek leave to address an emergency that could adversely impact Kentucky Power or its customers. In the event the Commission initiates an investigation or a complaint is filed with the Commission regarding the Company's rates, the Company retains the right to defend the reasonableness of its rates in such proceedings.

6. Tariff P.P.A.

(a) Kentucky Power's proposed changes to Tariff P.P.A., as set forth in the testimony of Company Witness Vaughan and modified by Sections 2 and 3 above, are approved.

(b) A revised version of Tariff P.P.A. incorporating the modifications described in Sections 2 and 3 above is included as **EXHIBIT 4.**

7. Depreciation Rates

(a) Kentucky Power and the Settling Intervenors agree that Big Sandy Unit 1 has an expected life of 20 years following its conversion from a coal-fired to a natural gas-fired generating unit. The depreciation rates for Big Sandy Unit 1 have been adjusted to reflect the 20 year expected life. Kentucky Power and the Signatory Parties retain the right to propose updated depreciation rates for Big Sandy Unit 1 in future proceedings to reflect updates to the expected life.

(b) Kentucky Power has adjusted depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant to remove terminal net salvage costs. Kentucky Power retains the right to propose updated depreciation rates for Big Sandy Unit 1 and for the Mitchell Plant in future proceedings to include terminal net salvage costs, and the Settling Intervenors retain the right to challenge the inclusion of such costs in future proceedings.

(c) Kentucky Power's updated depreciation rates are included as **EXHIBIT 5**.

8. Return on Equity, Capitalization, WACC, and GRCF

(a) Kentucky Power shall be authorized a 9.75% return on equity. The authorized return on equity of 9.75% will be used in the calculation of the Company's Environmental Surcharge factor (for non-Rockport environmental projects) and the carrying charges for the Rockport Deferral and Decommissioning Rider regulatory assets.

(b) Kentucky Power will update its capitalization to reflect short term debt as 1% of the Company's total capital structure. The annual interest rate for the short term debt will be set at 1.25%.

(c) Kentucky Power shall utilize a weighted average cost of capital ("WACC") of 9.11% including a gross revenue conversion factor ("GRCF") of 1.6433%. The GRCF does not include a Section 199 deduction. This WACC and GRCF shall remain constant (including for the riders and surcharges described in Paragraph 8(a) above) until such time as the Commission sets base rates in the Company's next base rate case proceeding. The calculations of the WACC and GRCF are shown on **EXHIBIT 6**.

9. Storm Damage Expense Amortization

(a) Kentucky Power will recover and amortize the remaining unamortized balance of its deferred storm expense regulatory asset authorized in Case No. 2012-00445 over a period of five years beginning January 1, 2018, consistent with the recommendation of KIUC. The unamortized balance of the regulatory asset authorized in Case No. 2012-00445 will total $6,087,000 on December 31, 2017 and will be amortized over five years at an annual amount of $1,217,400.

(b) Kentucky Power will recover and amortize the deferred storm expense regulatory asset authorized in Case No. 2016-00180 over a period of 5 years beginning January 1, 2018 consistent with the testimony of Company Witness Wohnhas. The balance of the regulatory asset authorized in Case No. 2016-00180 totals $4,377,336 and will be amortized over five years at an annual amount of $875,467.

(c) The combined balance of the Kentucky Power's deferred storm expense regulatory assets (the remaining unamortized balance authorized in Case No. 2012-00445 and the amount authorized in Case No. 2016-00180) will total $10,464,336 on December 31, 2017 and will be amortized over five years at an annual amount of $2,092,867.

10. Kentucky Economic Development Surcharge

(a) Kentucky Power's new Kentucky Economic Development Surcharge Tariff ("Tariff K.E.D.S.") shall be approved with rates amended as follows:

(i) The KEDS rate for residential customers will be set at $0.10 per meter instead of $0.25 as proposed by the Company.

(ii) The KEDS rate for non-residential customers for which the KEDS applies will be set at $1.00 per meter instead of $0.25 as proposed by the Company.

(b) All KEDS funds collected by Kentucky Power shall be matched dollar-for-dollar by Kentucky Power from shareholder funds. The proceeds of KEDS and Kentucky Power's shareholder contribution shall be used by Kentucky Power for economic development projects, including the training of local economic development officials, in the Company's service territory. The KEDS, and the matching shareholder contribution, shall remain in effect until changed by order of the Commission.

(c) Kentucky Power will continue to file on or before March 31st of each year a report with the Commission describing: (i) the amount collected through the Economic Development Surcharge; and (ii) the matching amount contributed by Kentucky Power from shareholder funds. The annual report to be filed by the Company shall also describe the amount, recipients, and purposes of its expenditure of the funds collected through the Economic Development Surcharge and shareholder contribution.

(d) Kentucky Power shall serve a copy of the annual report to be filed with the Commission in accordance with subparagraph (c) on counsel for all parties to this proceeding.

11. Backup and Maintenance Service

(a) In order for Marathon Petroleum LP ("Marathon") to evaluate the economics of self or co-generation, Kentucky Power and Marathon will begin negotiations regarding the terms, conditions and pricing for backup and maintenance service within 30 days of a Commission Order approving this provision and will complete negotiations within the next 120 days. Prior to the start of the 120 day negotiation period, Marathon will provide Kentucky Power with specific information regarding the MW size of a potential self or co-generation facility and the type of generation technology being considered.

(b) If Kentucky Power and Marathon cannot reach an agreement on backup and maintenance service within 120 days, Kentucky Power and Marathon agree to submit the issue to the Commission for resolution.

12. School Energy Manager Program

(a) Kentucky Power shall seek leave from the Commission to include up to $200,000 for the School Energy Manager Program in its each of its 2018 and 2019 DSM Program offerings.

(b) Kentucky Power and KSBA both expressly acknowledge that there is in Case No. 2017-00097 a currently-pending Commission investigation of the Company's DSM programs and funding and that the outcome of that investigation could impact the School Energy Manager Program.

13. Tariff K-12 School

(a) Kentucky Power shall continue its current Pilot Tariff K-12 School but shall remove the Pilot designation as set forth in **Exhibit 7**. Tariff K-12 School shall be available for general service to all K-12 schools in the Company's service territory, public and private, with normal maximum demands greater than 100 kW. Tariff K-12 School shall reflect rates for customers taking service under the tariff designed to produce annually in the aggregate $500,000 less from Tariff K-12 School customers than would be produced under the new L.G.S. rates to be established under this Settlement Agreement from customers eligible to take service under Tariff K-12 School. The aggregate total revenues to be produced by Tariff K-12 School and Tariff L.G.S. shall be equal to the revenues that would be produced in the aggregate by the new rates in the absence of Tariff K-12 School. Service under Tariff K-12 School shall be optional.

14. <u>Bill Format Changes</u>

(a) The bill formatting changes proposed by the Company in Case No. 2017-00231 and consolidated into this case by Commission Order dated July 17, 2017, to the extent not already approved, are approved.

(b) Within 180 days of a Commission Order approving this Settlement, Kentucky Power will conduct a training session with representatives from its municipal clients and KLC to explain the new bill format and tools available to clients to evaluate their electric usage.

15. <u>Renewable Power Option Rider</u>

(a) The proposed changes to the Company's Green Pricing Option Rider, including renaming the rider to the Renewable Power Option Rider ("Rider R.P.O."), are approved except that the availability of service provision for Option B will state the following:

> "Customers who wish to directly purchase the electrical output and all associated environmental attributes from a renewable energy generator may contract bilaterally with the Company under Option B. Option B is available to customers taking metered service under the Company's I.G.S., and C.S.-I.R.P. tariffs, or multiple L.G.S. tariff accounts with common ownership under a single parent company that can aggregate multiple accounts to exceed 1000 kW of peak demand."

A revised version of Rider R.P.O. incorporating the modifications described above is included as **EXHIBIT 8**. Bills for customers receiving service under Rider R.P.O. will include a separate line item for Rider R.P.O. charges.

(b) Beginning no later than March 31, 2018, and no later than each March 31 thereafter, Kentucky Power will file a report with the Commission describing the previous year's activity under Rider R.P.O. This annual report will replace the semi-annual reports filed in Case No. 2008-00151.

16. Modifications To Kentucky Power's Rate Tariffs

In addition to the rate and tariff changes described and agreed to above, Kentucky Power and the Settling Intervenors agree that the following tariffs shall be modified or implemented as described below:

(a) The Customer charge for the Residential Class ("Tariff R.S.") shall be increased to $14.00 per month instead of the $17.50 per month proposed by the Company in its filing in this case.

(b) The Company is extending the termination date for Tariff C.S. – Coal and the amendments to Tariff C.S. – I.R.P. and Tariff E.D.R. approved in Case No. 2017-00099 from December 31, 2017 to December 31, 2018.

(c) The pole attachment rate under Tariff C.A.T.V. shall be $10.82 for attachments on two-user poles and $6.71 for attachments on three-user poles for all attachments instead of the $11.97 for attachments on two-user poles and $7.42 for attachments on three-user poles proposed by the Company in its filing in this case.

17. Filing Of Settlement Agreement With The Commission And Request For Approval

Following the execution of this Settlement Agreement, Kentucky Power and the Settling Intervenors shall file this Settlement Agreement with the Commission along with a joint request to the Commission for consideration and approval of this Settlement Agreement so that Kentucky

Power may begin billing under the approved adjusted rates for service rendered on or before January 19, 2018.

18. Good Faith And Best Efforts To Seek Approval

(a) This Settlement Agreement is subject to approval by the Public Service Commission.

(b) Kentucky Power and the Settling Intervenors shall act in good faith and use their best efforts to recommend to the Commission that this Settlement Agreement be approved in its entirety and without modification and that the rates and charges set forth herein be implemented.

(c) Kentucky Power and the Settling Intervenors filed testimony in this case. Kentucky Power also filed testimony in support of the Settlement Agreement. For purposes of any hearing, the Settling Intervenors and Kentucky Power waive all cross-examination of the other Signatory Parties' witnesses except for purposes of supporting this Settlement Agreement unless the Commission disapproves this Settlement Agreement. Each further stipulates and recommends that the Notice of Intent, Application, testimony, pleadings, and responses to data requests filed in this proceeding be admitted into the record.

(d) The Signatory Parties further agree to support the reasonableness of this Settlement Agreement before the Commission, and to cause their counsel to do the same, including in connection with any appeal from the Commission's adoption or enforcement of this Settlement Agreement.

(e) No party to this Settlement Agreement shall challenge any Order of the Commission approving the Settlement Agreement in its entirety and without modification.

19. Failure Of Commission To Approve Settlement Agreement

If the Commission does not accept and approve this Stipulation in its entirety, then any adversely affected Party may withdraw from the Stipulation within the statutory periods provided for rehearing and appeal of the Commission's order by (1) giving notice of withdrawal to all other Parties and (2) timely filing for rehearing or appeal. Upon the latter of (1) the expiration of the statutory periods provided for rehearing and appeal of the Commission's order and (2) the conclusion of all rehearing's and appeals, all Parties that have not withdrawn will continue to be bound by the terms of the Stipulation as modified by the Commission's order.

20. Continuing Commission Jurisdiction

This Settlement Agreement shall in no way be deemed to divest the Commission of jurisdiction under Chapter 278 of the Kentucky Revised Statutes.

21. Effect of Settlement Agreement

This Settlement Agreement shall inure to the benefit of, and be binding upon, the parties to this Settlement Agreement, their successors, and assigns.

22. Complete Agreement

This Settlement Agreement constitutes the complete agreement and understanding among the parties to this Settlement Agreement, and any and all oral statements, representations, or agreements. Any and all such oral statements, representations, or agreements made prior hereto or contained contemporaneously herewith shall be null and void and shall be deemed to have been merged into this Settlement Agreement.

23. Independent Analysis

The terms of this Settlement Agreement are based upon the independent analysis of the parties to this Settlement Agreement, are the product of compromise and negotiation, and reflect a fair, just, and reasonable resolution of the issues herein. Notwithstanding anything contained in this Settlement Agreement, Kentucky Power and the Settling Intervenors recognize and agree that the effects, if any, of any future events upon the income of Kentucky Power are unknown and this Settlement Agreement shall be implemented as written.

24. Settlement Agreement And Negotiations Are Not An Admission

(a) This Settlement Agreement shall not be deemed to constitute an admission by any party to this Settlement Agreement that any computation, formula, allegation, assertion, or contention made by any other party in these proceedings is true or valid. Nothing in this Settlement Agreement shall be used or construed for any purpose to imply, suggest or otherwise indicate that the results produced through the compromise reflected herein represent fully the objectives of the Signatory Parties.

(b) Neither the terms of this Settlement Agreement nor any statements made or matters raised during the settlement negotiations shall be admissible in any proceeding, or binding on any of the parties to this Settlement Agreement, or be construed against any of the parties to this Settlement Agreement, **except that** in the event of litigation or proceedings involving the approval, implementation or enforcement of this Agreement, the terms of this Settlement Agreement shall be admissible. This Settlement Agreement shall not have any precedential value in this or any other jurisdiction.

25. Consultation With Counsel

The parties to this Settlement Agreement warrant that they have informed, advised, and consulted with their respective counsel with regard to the contents and significance of this Settlement Agreement and are relying upon such advice in entering into this agreement.

26. Authority To Bind

Each of the signatories to this Settlement Agreement hereby warrant they are authorized to sign this agreement upon behalf of, and bind, their respective parties.

27. Construction Of Agreement

This Settlement Agreement is a product of negotiation among all parties to this Settlement Agreement, and no provision of this Settlement Agreement shall be construed in favor of or against any party hereto. This Settlement Agreement is submitted for purposes of this case only and is not to be deemed binding upon the parties hereto in any other proceeding, nor is it to be offered or relied upon in any other proceeding involving Kentucky Power or any other utility.

28. Counterparts

This Settlement Agreement may be executed in multiple counterparts.

29. Future Rate Proceedings

Nothing in this Settlement Agreement shall preclude, prevent, or prejudice any party to this Settlement Agreement from raising any argument or issue, or challenging any adjustment, in any future rate proceeding of Kentucky Power.

IN WITNESS WHEREOF, this Settlement Agreement has been agreed to as of this 22nd day of November 2017.

KENTUCKY POWER COMPANY

By: ______________________

Its: Counsel

KENTUCKY INDUSTRIAL UTILITY
CUSTOMERS, INC.

By: Michael L. Kurtz

Its: Counsel

KENTUCKY SCHOOL BOARDS
ASSOCIATION, INC.

By: Matthew Malone

Its: Legal Counsel

KENTUCKY LEAGUE OF CITIES

By: [signature]

Its: Director of Municipal Law & Training

KENTUCKY CABLE
TELECOMMUNICATION
ASSOCIATION, INC.

By: Jason K[illegible]

Its: KCTA Board Chairman

WAL-MART STORES EAST, LP AND
SAM'S EAST, INC.

By: CUJA

Its: Counsel

APPENDIX B

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Adjustments	Amounts
Capacity Charge Revenues Removal	($6,396,832)
Removal of Effects of Decommissioning Rider Revenue and Expenses	($18,512,331)
Eliminate Mitchell FGD Operating Expenses	($13,308,197)
Remove Mitchell plant FGD and Consumable inventory from Rate Base	($1,610,192)
Removal of Mitchell FGD Environmental Surcharge Rider Revenues	($538,417)
Remove Big Sandy Unit 1 Operation Rider Deferrals	($4,333,902)
Fuel Under (Over) Revenues	$4,574,472
Reset OSS Margin Baseline to 2016 Test Year OSS Margins	($8,800,856)
PPA Rider Synchronization Adjustment	$372,542
Remove DSM Revenue Expense	($5,503,380)
Remove HEAP Revenue and Expense	($246,772)
Remove Economic Development Surcharge Revenue and Expense	($303,011)
Tariff Migration Adjustment	$1,026,263
Customer Annualization Revenue Adjustment	($1,342,364)
Weather Normal Load Revenue Adjustment	$4,080,748
O&M Expense Interest on Customer Deposit	$67,254
Amortization of Major Storm Cost Deferral	$874,592
Postage Rate Decrease Adjustment	($6,656)
Eliminate Advertising Expense	$100,444
Adjust Pension and OPEB Expense	$148,679
Employee Related Group Benefit Expense	$429,241
Remove PJM BLIs From Base for FAC Inclusions	($516,659)
Adjustment to Include Purchase Power Limitation Expense in Rate Base	$3,150,582
Adjustment to Include Forced Outage Purchase Power Limitation in Base Rates	$882,204
Annualize NITS/PJM LSE OATT Expense	$3,825,858
Annualize PJM Admin Charges	$118,606
Amortization of NERC Cost Deferral	$14,275
Severance Expense Adjustment	$2,363
Annualization of Payroll Expense Adjustment	$244,837
Social Security Tax Base Adjustment	$26,009
Eliminate Non-Recoverable Business Expenses	$14,914
Plant Maintenance Normalization	($274,334)
Depreciation Annualization Adjustment Electric Plant in Service	$2,037,359
Decrease ARO Depreciation Expense to an Annualized Level	($3,818)
Decrease ARO Accretion Expense to an Annualized Level	($109,495)
Annualization of Cable Pole Attachment Revenue	$532,369
KPSC Maintenance Assessment	($1,801)
State Gross Receipts Tax Adjustment	$78,776

Interest Synchronization Adjustment (Per 8/7/2017 Amendment)	$6,449,828
AFUDC Offset Adjustment (Per 8/17/2017 Amendment)	$28,197
Adjustment to Recognize Accrued Surcharge Revenue Differences	($62,588)
Mitchell Plant ADSIT Amortization	$1,292,491
Decrease O&M for Vegetation Management Tree Trimming	($6,794,282)
Annualization of Property Taxes	$595,507

APPENDIX C

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

The following rates and charges are prescribed for the customers in the area served by Kentucky Power Company. All other rates and charges not specifically mentioned herein shall remain the same as those in effect under authority of this Commission prior to the effective date of this Order.

TARIFF R.S.
RESIDENTIAL SERVICE

Service Charge per month	$	14.00
Energy Charge per kWh	$	.09660
Storage Water Heating Provision - Per kWh	$	.06072
Load Management Water Heating Provision - Per kWh	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-L.M.-T.O.D.
RESIDENTIAL SERVICE LOAD MANAGEMENT TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14346
All kWh used during off-peak billing period	$	.06072
Separate Metering Provision Per Month	$	3.75
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D.
RESIDENTIAL SERVICE TIME-OF-DAY

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.14386
All kWh used during off-peak billing period	$	.06072
Home Energy Assistance Program Charge Per meter per month	$	.30

TARIFF R.S.-T.O.D. 2
EXPERIMENTAL RESIDENTIAL SERVICE TIME-OF-DAY 2

Service Charge per month	$	16.00
Energy Charge per kWh:		
All kWh used during summer on-peak billing period	$	.17832
All kWh used during winter on-peak billing period	$	.15342
All kWh used during off-peak billing period	$	.08094
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF R.S.D.
RESIDENTIAL DEMAND-METERED ELECTRIC SERVICE

Service Charge per month	$	17.50
Energy Charge per kWh:		
All kWh used during on-peak billing period	$	.09738
All kWh used during off-peak billing period	$	.07029
Demand Charge per kW	$	4.02
Home Energy Assistance Program Charge		
Per meter per month	$	.30

TARIFF G.S.
GENERAL SERVICE

Secondary Service:		
Service Charge per month	$	22.50
Energy Charge per kWh:		
Phase 1		
First 4,450 kWh per month	$	.10198
Over 4,450 kWh per month	$	.10188
Phase 2		
First 4,450 kWh per month	$	.09807
Over 4,450 kWh per month	$	.09798
Demand Charge per kW greater than 10 kW		
Phase 1	$	4.00
Phase 2	$	6.00
Primary Service:		
Service Charge per month	$	75.00
Energy Charge per kWh:		
First 4,450 kWh per month	$	.08629
Over 4,450 kWh per month	$	.08659
Demand Charge per kW greater than 10 kW	$	7.18

Subtransmission Service:

Service Charge per month	$ 364.00
Energy Charge per kWh:	
First 4,450 kWh per month	$ .07822
Over 4,450 kWh per month	$ .07855
Demand Charge per kW greater than 10 kW	$ 5.74

TARIFF G.S.
GENERAL SERVICE
RECREATIONAL LIGHTING SERVICE PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh	$ .09968

TARIFF G.S.
GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .14423
All kWh used during off-peak billing period	$ .06072

TARIFF G.S.
GENERAL SERVICE
OPTIONAL UNMETERED SERVICE PROVISION

Service Charge per month	$ 14.00
Energy Charge per kWh:	
Phase 1	
First 4,450 kWh per month	$ .10198
Over 4,450 kWh per month	$ .10188
Phase 2	
First 4,450 kWh per month	$ .09807
Over 4,450 kWh per month	$ .09798

TARIFF S.G.S.-T.O.D.
SMALL GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during summer on-peak billing period	$ .17034
All kWh used during winter on-peak billing period	$ .14372
All kWh used during off-peak billing period	$ .07511

TARIFF M.G.S.-T.O.D.
MEDIUM GENERAL SERVICE TIME-OF-DAY

Service Charge per month	$ 22.50
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .16747
All kWh used during off-peak billing period	$ .06072

TARIFF L.G.S.
LARGE GENERAL SERVICE

Secondary Service Voltage:	
Service Charge per month	$ 85.00
Energy Charge per kWh	$ .07712
Demand Charge per kW	$ 7.97
Primary Service Voltage:	
Service Charge per month	$ 127.50
Energy Charge per kWh	$ .06711
Demand Charge per kW	$ 7.18
Sub-transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge per kWh	$ .05112
Demand Charge per kW	$ 5.74
Transmission Service Voltage:	
Service Charge per month	$ 660.00
Energy Charge per kWh	$ .04997
Demand Charge per kW	$ 5.60
All Service Voltages:	
Excess Reactive Charge per KVA	$ 3.46

TARIFF L.G.S.
LARGE GENERAL SERVICE
LOAD MANAGEMENT TIME-OF-DAY PROVISION

Service Charge per month	$ 85.00
Energy Charge per kWh:	
All kWh used during on-peak billing period	$ .14063
All kWh used during off-peak billing period	$ .06088

TARIFF L.G.S. – T.O.D.
LARGE GENERAL SERVICE TIME-OF-DAY

Secondary Service Voltage:		
Service Charge per month	$	85.00
Energy Charge:		
On-Peak Energy Charge per kWh	$	.09670
Off-Peak Energy Charge per kWh	$	.04132
Demand Charge per kW	$	10.87
Primary Service Voltage:		
Service Charge per month	$	127.50
Energy Charge:		
On-Peak Energy Charge per kWh	$	.09300
Off-Peak Energy Charge per kWh	$	.04010
Demand Charge per kW	$	7.84
Sub-transmission Service Voltage:		
Service Charge per month	$	660.00
Energy Charge:		
On-Peak Energy Charge per kWh	$	.09176
Off-Peak Energy Charge per kWh	$	.03970
Demand Charge per kW	$	1.52
Transmission Service Voltage:		
Service Charge per month	$	660.00
Energy Charge:		
On-Peak Energy Charge per kWh	$	.09049
Off-Peak Energy Charge per kWh	$	.03928
Demand Charge per kW	$	1.49
All Service Voltages:		
Excess Reactive Charge per KVA	$	3.46

TARIFF I.G.S.
INDUSTRIAL GENERAL SERVICE

Secondary Service Voltage:		
Service Charge per month	$	276.00
Energy Charge per kWh	$	.02663
Demand Charge per kW		
Of Monthly On-Peak Billing Demand	$	24.13
Of Monthly Off-Peak Billing Demand	$	1.60

Primary Service Voltage:

Service Charge per month	$ 276.00
Energy Charge per kWh	$ .02553
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 20.57

Sub-transmission Service Voltage:

Service Charge per month	$ 794.00
Energy Charge per kWh	$ .02793
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.69
Of Monthly Off-Peak Billing Demand	$ 1.51

Transmission Service Voltage:

Service Charge per month	$1,353.00
Energy Charge per kWh	$ .02792
Demand Charge per kW	
Of Monthly On-Peak Billing Demand	$ 13.26
Of Monthly Off-Peak Billing Demand	$ 1.49

All Service Voltages:
Reactive demand charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the kW of monthly metered demand is $.69 per KVAR.

Minimum Demand Charge
The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates per kW:

Secondary	$ 25.83
Primary	$ 22.21
Subtransmission	$ 15.30
Transmission	$ 14.86

TARIFF M.W.
MUNICIPAL WATERWORKS

Service Charge per month	$ 22.90
Energy Charge - All kWh per kWh	$ .09135

Subject to a minimum monthly charge equal to the sum of the service charge plus $8.89 per kW as determined from customer's total connected load.

TARIFF O.L.
OUTDOOR LIGHTING

OVERHEAD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	8.50
150 Watts (16,000 Lumens)	$	9.30
200 Watts (22,000 Lumens)	$	10.90
250 Watts (28,000 Lumens)	$	15.04
400 Watts (50,000 Lumens)	$	16.01
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	9.04
400 Watts (20,000 Lumens)	$	14.64

POST-TOP LIGHTING SERVICE

High Pressure Sodium per Lamp:		
100 Watts (9,500 Lumens)	$	14.05
150 Watts (16,000 Lumens)	$	23.30
100 Watts Shoe Box (9,500 Lumens)	$	29.50
250 Watts Shoe Box (28,000 Lumens)	$	24.99
400 Watts Shoe Box (50,000 Lumens)	$	36.16
Mercury Vapor per Lamp:		
175 Watts (7,000 Lumens)	$	10.59

FLOOD LIGHTING SERVICE

High Pressure Sodium per Lamp:		
200 Watts (22,000 Lumens)	$	13.10
400 Watts (50,000 Lumens)	$	17.06
Metal Halide		
250 Watts (20,500 Lumens)	$	15.27
400 Watts (36,000 Lumens)	$	18.39
1,000 Watts (110,000 Lumens)	$	30.94
250 Watts Mongoose (19,000 Lumens)	$	20.57
400 Watts Mongoose (40,000 Lumens)	$	23.59

Per Month:		
Wood Pole	$	3.40
Overhead Wire Span not over 150 Feet	$	2.00
Underground Wire Lateral not over 50 Feet	$	7.40

Per Lamp plus $0.02725 x kWh in Sheet No. 14-3 in Company's tariff

TARIFF S.L.
STREET LIGHTING

Rate per Lamp:		
Overhead Service on Existing Distribution Poles		
High Pressure Sodium		
100 Watts (9,500 Lumens)	$	7.02
150 Watts (16,000 Lumens)	$	7.55
200 Watts (22,000 Lumens)	$	8.95
400 Watts (50,000 Lumens)	$	11.71
Service on New Wood Distribution Poles		
High Pressure Sodium		
100 Watts (9,500 Lumens)	$	10.80
150 Watts (16,000 Lumens)	$	11.55
200 Watts (22,000 Lumens)	$	12.95
400 Watts (50,000 Lumens)	$	16.61
Service on New Metal or Concrete Poles		
High Pressure Sodium		
100 Watts (9,500 Lumens)	$	27.45
150 Watts (16,000 Lumens)	$	28.15
200 Watts (22,000 Lumens)	$	26.70
400 Watts (50,000 Lumens)	$	27.11

Per Lamp plus $0.02725 x kWh in Sheet No. 15-2 in Company's tariff

TARIFF C.A.T.V.
CABLE TELEVISION POLE ATTACHMENT

Charge for attachments		
On a two-user pole	$	10.82
On a three-user pole	$	6.71

TARIFF COGEN/SPP I
COGNERATION AND/OR SMALL POWER PRODUCTION
100 KW OR LESS

Monthly Metering Charges:		
Single Phase:		
Standard Measurement	$	9.25
Time-of-Day Measurement	$	9.85

Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF COGEN/SPP II
COGNERATION AND/OR SMALL POWER PRODUCTION
OVER 100 KW

Metering Charges:		
Single Phase:		
Standard Measurement	$	9.25
Time-of-Day Measurement	$	9.85
Polyphase:		
Standard Measurement	$	12.10
Time-of-Day Measurement	$	12.40
Energy Credit per kWh:		
Standard Meter – All kWh	$	.03240
Time-of-Day Meter:		
On-Peak kWh	$	.03860
Off-Peak kWh	$	.02790
Capacity Credit:		
Standard Meter per kW	$	3.11
Time-of-Day Meter per kW	$	7.47

TARIFF K.E.D.S.
KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE

Per month per account:		
Residential	$	.00
All Other	$	1.00

TARIFF C.C.
CAPACITY CHARGE

Energy Charge per kWh:		
Service Tariff		
I.G.S.	$	.000749
All Other	$	.001435

RIDER R.P.O.
RENEWABLE POWER OPTION RIDER
OPTION A

Solar RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage Purchase per kWh consumed	$	.01000
Wind RECs:		
Block Purchase per 100 kWh per month	$	1.00
All Usage per kWh consumed	$	.01000
Hydro & Other RECs:		
Block Purchase per 100 kWh per month	$	.30
All Usage per kWh consumed	$	.00300

RIDER A.F.S.
ALTERNATE FEED SERVICE RIDER

Monthly Rate for Annual Test of Transfer Switch/Control Module	$	14.67
Monthly Capacity Reservation Demand Charge per kW	$	6.29

APPENDIX D

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

ENVIRONMENTAL COMPLIANCE PLAN

Project	Plant	Pollutant	Description	In-Service Year
			Previously Approved Environmental Compliance Projects	
1	Mitchell	NOx, SO2, and SO3	Mitchell Units 1 & 2, Water Injection, Low NOx Burners, Low NOx Burner Modification, SCR, FGD, Landfill, Coal Blending Facilities & SO3 Mitigation	1993-1994-2002-2007
2	Mitchell	SO2, NOx and Gypsum	Mitchell Plant Common CEMS, Replace Burner Barrier Valves & Gypsum Material Handling Facilities	1993-1994-2007
3	Rockport	SO2 / NOx	Continuous Emission Monitors ("CEMS")	1994
4	Rockport	NOx, Fly Ash, & Bottom Ash	Rockport Units 1 & 2 Low NOx Burners, Over Fire Air & Landfill	2003-2008
5	Mitchell & Rockport	SO2, NOx, Particulates & VOC and etc.	Title V Air Emissions Fees at Mitchell and Rockport Plants	Annual
6	Big Sandy, Mitchell & Rockport	NOx	Costs Associated with NOx Allowances	As Needed
7	Big Sandy, Mitchell & Rockport	SO2	Costs Associated with SO2 Allowances	As Needed
8	Big Sandy, Mitchell & Rockport	SO2 / NOx	Costs Associated with the CSAPR Allowances	As Needed
9	Mitchell	Particulates	Mitchell Units 1 & 2 - Precipitator Modifications	2007-2013
10	Mitchell	Particulates	Mitchell Units 1 & 2 - Bottom Ash & Fly Ash Handling	2008-2010
11	Mitchell	Mercury	Mitchell Units 1 & 2 - Mercury Monitoring ("MATS")	2014
12	Mitchell	Selenium	Mitchell Units 1 & 2 - Dry Fly Ash Handling Conversion	2014
13	Mitchell	Fly Ash, Bottom Ash, Gypsum & WWTP Solids	Mitchell Units 1 & 2 - Coal Combustion Waste Landfill	2014
14	Mitchell	Particulates	Mitchell Unit 2 - Electrostatic Precipitator Upgrade	2015
15	Rockport	Particulates	Rockport Units 1 & 2 - Precipitator Modifications	2004-2009
16	Rockport	Mercury	Rockport Units 1 & 2 - Activated Carbon Injection ("ACI") & Mercury Monitoring	2009-2010

17	Rockport	Hazardous Air Pollutants ("HAPS")	Rockport Units 1 & 2 - Dry Sorbent Injection	2015
18	Rockport	Fly Ash & Bottom Ash	Rockport Plant Common - Coal Combustion Waste Landfill Upgrade to Accept Type 1 Ash	2013 & 2015
			Proposed Environmental Compliance Projects	
19	Rockport	NOx	Rockport Unit 1 - Selective Catalytic Reduction equipment	2017
20	Mitchell Rockport	SO2 / NOx, Mercury, Particulates, Hazardous Air Pollutants ("HAPS")	Cost of consumables used in conjunction with approved ECP projects including the cost of the consumables used and a return on consumable inventories. Consumables include, but are not limited to sodium bicarbonate, activated carbon, anhydrous ammonia, trona, lime hydrate, limestone, polymer, and urea.	As Needed

APPENDIX E

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

MONTHLY BASE PERIOD REVENUE REQUIREMENT

Billing Month	Base Period Cost
January	$ 3,664,681
February	3,581,017
March	3,353,024
April	3,661,574
May	3,595,145
June	3,827,332
July	3,747,320
August	3,888,262
September	3,636,247
October	3,824,697
November	3,717,340
December	3,882,677
	$ 44,379,316

APPENDIX F

APPENDIX TO AN ORDER OF THE KENTUCKY PUBLIC SERVICE COMMISSION IN CASE NO. 2017-00179 DATED JAN 18 2018

Commission Staff Adjustments to the Revenue Requirement in the Settlement Agreement
Case No. 2017-00179
Kentucky Power Company (Kentucky Jurisdiction)

	Pre-Tax Operating Income Amount	NOI Amount	GRCF		Staff RR Amount
Increase Per Settlement					31,780,734
Operating Income Issues					
OSS Rider Adjustment	(486,412)	(361,693)	1.352116	$	(489,051)
Theft Recovery Revenue	(166,198)	(123,584)	1.352116	$	(167,100)
Purchased Power Adj (WP 26&27)	(4,032,786)	(2,998,755)	1.352116	$	(4,054,664)
Relocation Expense	(132,109)	(98,235)	1.352116	$	(132,826)
Cost of Capital Issues					
Total Change in ROE and capitalization		(476,714)	1.352116	$	(644,573)
Change in GCRF					(13,943,890)
Total Adjustments to the Settlement Agreement				$	(19,432,104)
Recommended Change in Base Rates				$	12,348,630

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Calculation of Proposed Peaking Unit Equivalent Cost Calculation Adjustment

	Firm Gas Adjustment Calculation					
	$/MMBtu	Heat Rate	$/MWh	Startup Costs $/MWh	Variable O&M $/MWh	Total $/MWh Adjustment
January	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
February	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
March	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
April	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
May	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
June	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
July	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
August	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
September	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
October	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
November	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
December	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87

Proposed new Peaking Unit Equivalent cost calculation = (Daily Gas Price * Heat Rate/1000) + Total $/MWh Adjustment

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

**KENTUCKY POWER HEARING
EXHIBIT 1**

Ceredo Combustion Turbines
Historical Variable O&M Costs

Year	Month	Unitname	MWH	Total Accounting Rate	Fuel Rate 151	Handling Rate 152	O&M Cost / MWH	VOM Cost
2013	January	Ceredo	1,224	65.28	13.62	0.45	6.45	7,895
2013	February	Ceredo	306	66.92	15.56	2.06	5.92	1,812
2013	March	Ceredo	728	66.42	16.83	1.84	8.94	6,508
2013	April	Ceredo	0	0	0	0	0.00	-
2013	May	Ceredo	662	74.83	15.23	3.90	7.17	4,747
2013	June	Ceredo	86	116.04	12.73	6.11	40.36	3,471
2013	July	Ceredo	2,983	59.18	15.25	0.27	1.30	3,878
2013	August	Ceredo	0	0	0	0	0.00	-
2013	September	Ceredo	645	54.67	13.79	1.36	6.71	4,328
2013	October	Ceredo	0	0	0	0	0.00	-
2013	November	Ceredo	100	184.66	24.79	8.04	9.31	931
2013	December	Ceredo	697	69.97	16.24	2.16	7.51	5,234
2014	January	Ceredo	11,707	27.35	27.24	0.12	0.72	8,429
2014	February	Ceredo	8,880	33.81	33.62	0.20	1.10	9,768
2014	March	Ceredo	6,411	28.58	28.33	0.25	0.81	5,193
2014	April	Ceredo	510	21.76	19.48	2.28	23.62	12,044
2014	May	Ceredo	876	18.61	17.38	1.24	5.07	4,441
2014	June	Ceredo	88	2,223	1,067	1,157	137.08	12,063
2014	July	Ceredo	155	2,744	2,057	687	49.90	7,734
2014	August	Ceredo	366	6,402	5,545	857	25.06	9,172
2014	September	Ceredo	70	567	567	0	246.72	17,270
2014	October	Ceredo	501	7,129	7,367	-238	26.03	13,039
2014	November	Ceredo	0	0	0	0	0.00	-
2014	December	Ceredo	507	14.96	13.78	1.18	21.54	10,918
2015	January	Ceredo	1,764	15.26	14.69	0.56	5.51	9,720
2015	February	Ceredo	3,405	16.53	16.21	0.31	1.20	4,086
2015	March	Ceredo	909	14.43	13.76	0.67	3.06	2,777
2015	April	Ceredo	0	0.00	0.00	0.00	0.00	-
2015	May	Ceredo	5,224	11.32	11.21	0.11	1.16	6,060
2015	June	Ceredo	3,134	9.36	9.17	0.19	2.00	6,268
2015	July	Ceredo	2,994	11.39	11.21	0.18	2.09	6,242
2015	August	Ceredo	1,347	11.07	10.55	0.52	3.71	4,991
2015	September	Ceredo	1,647	10.65	10.09	0.56	7.46	12,287
2015	October	Ceredo	0	0.00	0.00	0.00	0.00	-
2015	November	Ceredo	395	9.63	7.74	1.90	4.19	1,653
2015	December	Ceredo	0	0.00	0.00	0.00	0.00	-
			58,321				3.48 Avg VOM $/MWh	202,956

Ceredo 1	Date	Start Cost
	11/4/2016	$ 2,940.67
	11/5/2016	$ 2,932.65
	11/6/2016	$ 2,932.65
	11/4/2016	$ 2,940.67
	11/5/2016	$ 2,932.65
	11/6/2016	$ 2,932.65
	11/7/2016	$ 2,932.65
	11/8/2016	$ 2,950.27
	11/9/2016	$ 2,953.19
	11/10/2016	$ 2,945.89
	11/11/2016	$ 2,934.22
	11/12/2016	$ 2,929.11
	11/13/2016	$ 2,929.11
	11/14/2016	$ 2,929.11
	11/15/2016	$ 2,945.89
	11/16/2016	$ 2,962.68
	11/17/2016	$ 2,967.78
	11/18/2016	$ 2,949.54
	11/19/2016	$ 2,970.70
	11/20/2016	$ 2,970.70
	11/21/2016	$ 2,970.70
	11/22/2016	$ 2,988.94
	11/23/2016	$ 2,983.84
	11/24/2016	$ 2,981.65
	11/25/2016	$ 2,981.65
	11/26/2016	$ 2,981.65
	11/27/2016	$ 2,981.65
	11/28/2016	$ 2,981.65
	11/29/2016	$ 2,993.32
	11/30/2016	$ 3,001.35
	12/1/2016	$ 3,024.37
	12/2/2016	$ 3,030.21
	12/3/2016	$ 3,028.02
	12/4/2016	$ 3,028.02
	12/5/2016	$ 3,028.02
	12/6/2016	$ 3,044.07
	12/7/2016	$ 3,056.47
	12/8/2016	$ 3,060.85
	12/9/2016	$ 3,056.47
	12/10/2016	$ 3,063.04
	12/11/2016	$ 3,063.04
	12/12/2016	$ 3,063.04
	12/13/2016	$ 3,049.18
	12/14/2016	$ 3,049.18
	12/15/2016	$ 3,044.80
	12/16/2016	$ 3,048.45
	12/17/2016	$ 3,034.58
	12/18/2016	$ 3,034.58
	12/19/2016	$ 3,034.58
	12/20/2016	$ 3,047.72
	12/21/2016	$ 3,032.39
	12/22/2016	$ 3,044.80
	12/23/2016	$ 3,047.72
	12/24/2016	$ 3,048.45
	12/25/2016	$ 3,048.45
	12/26/2016	$ 3,048.45
	12/27/2016	$ 3,048.45
	12/28/2016	$ 3,052.82
	12/29/2016	$ 3,045.53
	12/30/2016	$ 3,049.91
	12/31/2016	$ 3,049.91

	$ 3,005.84	Avg		
		min run	MW	$/MWh start cost
use	3000	1	100	30

Ceredo 1	Date	Start Cost
	1/1/2017	$ 3,045.38
	1/2/2017	$ 3,045.38
	1/3/2017	$ 3,045.38
	1/4/2017	$ 3,032.25
	1/5/2017	$ 3,033.71
	1/6/2017	$ 3,027.14
	1/7/2017	$ 3,030.79
	1/8/2017	$ 3,030.79
	1/9/2017	$ 3,030.79
	1/10/2017	$ 3,011.82
	1/11/2017	$ 3,019.85
	1/12/2017	$ 3,022.77
	1/13/2017	$ 3,029.33
	1/14/2017	$ 3,030.79
	1/15/2017	$ 3,030.79
	1/16/2017	$ 3,030.79
	1/17/2017	$ 3,030.79
	1/18/2017	$ 3,027.87
	1/19/2017	$ 3,022.04
	1/20/2017	$ 3,022.04
	1/21/2017	$ 3,018.39
	1/22/2017	$ 3,018.39
	1/23/2017	$ 3,018.39
	1/24/2017	$ 3,015.47
	1/25/2017	$ 3,022.77
	1/26/2017	$ 3,023.50
	1/27/2017	$ 3,034.44
	1/28/2017	$ 3,023.50
	1/29/2017	$ 3,023.50
	1/30/2017	$ 3,023.50
	1/31/2017	$ 3,019.12
	2/1/2017	$ 3,015.47
	2/2/2017	$ 3,015.47
	2/3/2017	$ 3,014.74
	2/4/2017	$ 3,007.44
	2/5/2017	$ 3,007.44
	2/6/2017	$ 3,007.44
	2/7/2017	$ 3,000.88
	2/8/2017	$ 3,008.90
	2/9/2017	$ 3,010.36
	2/10/2017	$ 3,014.01
	2/11/2017	$ 2,998.69
	2/12/2017	$ 2,998.69
	2/13/2017	$ 2,998.69
	2/14/2017	$ 3,001.61
	2/15/2017	$ 2,995.04
	2/16/2017	$ 3,001.61
	2/17/2017	$ 2,992.85
	2/18/2017	$ 2,981.91
	2/19/2017	$ 2,981.91
	2/20/2017	$ 2,981.91
	2/21/2017	$ 2,981.91
	2/22/2017	$ 2,965.13
	2/23/2017	$ 2,963.67
	2/24/2017	$ 2,972.42
	2/25/2017	$ 2,964.40
	2/26/2017	$ 2,964.40
	2/27/2017	$ 2,964.40
	2/28/2017	$ 2,965.13
	3/1/2017	$ 2,971.29
	3/2/2017	$ 2,976.40

Ceredo 1	Date		Start Cost
	3/3/2017	$	2,974.94
	3/4/2017	$	2,972.02
	3/5/2017	$	2,972.02
	3/6/2017	$	2,972.02
	3/7/2017	$	2,984.42
	3/8/2017	$	2,979.31
	3/9/2017	$	2,986.61
	3/10/2017	$	2,998.29
	3/11/2017	$	3,009.23
	3/12/2017	$	2,998.29
	3/13/2017	$	3,009.23
	3/14/2017	$	3,016.53
	3/15/2017	$	3,017.99
	3/16/2017	$	3,014.34
	3/17/2017	$	3,000.47
	3/18/2017	$	2,997.56
	3/19/2017	$	2,997.56
	3/20/2017	$	2,997.56
	3/21/2017	$	3,003.39
	3/22/2017	$	3,013.61
	3/23/2017	$	3,008.50
	3/24/2017	$	3,000.47
	3/25/2017	$	2,998.29
	3/26/2017	$	2,998.29
	3/27/2017	$	2,998.29
	3/28/2017	$	3,008.50
	3/29/2017	$	3,005.58
	3/30/2017	$	3,011.42
	3/31/2017	$	3,012.15
	4/1/2017	$	3,011.73
	4/2/2017	$	3,011.73
	4/3/2017	$	3,011.73
	4/4/2017	$	3,008.81
	4/5/2017	$	3,015.38
	4/6/2017	$	3,024.86
	4/7/2017	$	3,024.86
	4/8/2017	$	3,021.21
	4/9/2017	$	3,021.21
	4/10/2017	$	3,021.21
	4/11/2017	$	3,019.75
	4/12/2017	$	3,012.46
	4/13/2017	$	3,013.19
	4/14/2017	$	3,013.92
	4/15/2017	$	3,013.92
	4/16/2017	$	3,013.92
	4/17/2017	$	3,013.92
	4/18/2017	$	3,016.11
	4/19/2017	$	3,012.46
	4/20/2017	$	3,016.11
	4/21/2017	$	3,012.46
	4/22/2017	$	3,008.81
	4/23/2017	$	3,008.81
	4/24/2017	$	3,008.81
	4/25/2017	$	3,004.43
	4/26/2017	$	3,002.97
	4/27/2017	$	3,005.16
	4/28/2017	$	3,005.16
	4/29/2017	$	3,013.92
	4/30/2017	$	3,013.92
	5/1/2017	$	3,003.35

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Electronic Application Of Kentucky Power Company For (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2017 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; (4) An Order Approving Accounting Practices To Establish Regulatory Assets And Liabilities; And (5) An Order Granting All Other Required Approvals And Relief	)))))))))	Case No. 2017-00179

DIRECT TESTIMONY OF

ALEX E. VAUGHAN

ON BEHALF OF KENTUCKY POWER COMPANY

KIUC HEARING EXHIBIT 1

rates for these items and the actual costs incurred. This difference can be tracked effectively through the Company's Tariff PPA. If these FERC proceedings result in a reduction in the PJM LSE OATT charges for Kentucky Power's customers, the proposed tracking mechanism would allow the Company to flow those reductions to its customers in short order. If this tracking mechanism is approved, the Company would recover from customers only the actual amount of cost incurred for wholesale transmission service, not a dollar less or more.

Q. WHAT IS THE PROPOSED LEVEL OF PJM LSE OATT CHARGES AND CREDITS TO BE INCLUDED IN BASE RATES?

A. The adjusted test year Kentucky retail jurisdictional total of net PJM LSE OATT charges and credits included in base rates is $74,377,364. This amount has grown from $53,779,456 in Case No. 2014-00396.

(b) FAC Purchased Power Limitations

Q. WHAT OTHER CHANGES TO THE PURCHASE POWER ADJUSTMENT RIDER IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company is proposing to include a level of expense in its base rates related to the FAC Purchased Power Limitation that is generally driven by the peaking unit equivalent calculation and the forced outage purchase power limitation. The Company would then, on a monthly basis, track the amount of purchase power costs excluded from recovery through the FAC above or below the base rate level using deferral accounting. The annual net over or under collection of these FAC-excluded purchase power costs, as compared to the annual amount included in base rates, would then be collected from or credited to customers through the operation of Tariff PPA.

Q. PLEASE DESCRIBE THE FAC PURCHASED POWER LIMITATION AND WHY THE DIFFERENCES BETWEEN ACTUAL FAC PURCHASED POWER LIMITATION EXPENSE AND THE AMOUNT EMBEDDED IN BASE RATES SHOULD BE TRACKED THROUGH THE PURCHASE POWER ADJUSTMENT RIDER?

A. The FAC Purchase Power Limitation is a calculation that caps the amount of purchase power expense to be recovered in the Company's monthly FAC surcharge. The calculation compares the cost of actual purchased power on an hourly basis[6] to the cost of the Company's highest cost unit or the theoretical peaking unit equivalent and caps the FAC-recoverable purchase power expense at the cost ($/MWh) of the highest cost generating unit (Company owned or peaking unit equivalent). The peaking unit equivalent was created as a proxy because Kentucky Power does not own any peaking units. The FAC Purchase Power Limitation is applied to all[7] purchased power expense used to serve the Company's customers.

The very structure of the FAC Purchase Power Limitation and the peaking unit equivalent calculation promotes variability and volatility because it relies on factors that are outside of the Company's control. Moreover, because the FAC Purchase Power Limitation applies regardless of whether all of the Company's generation resources are being dispatched by PJM in that hour, if some or all resources are on a scheduled maintenance outage, or if it is simply more economic in that hour to purchase PJM spot market energy rather than generate it from Kentucky Power's generating fleet, the

[6] There is a monthly threshold test that is first applied to see if the hourly calculation is necessary.
[7] All purchased power expense excluding that which is characterized as being attributable to generator forced outages which is excluded from FAC recovery separately.

amount of purchased power expense excluded from the FAC is unpredictable and incredibly variable.

The variable nature of the FAC Purchase Power Limitation is shown in the historic period studied[8] by the Company for purposes of Adjustment 26. During that period, the monthly FAC Purchase Power Limitation calculation yielded as little as $19 and as much as $7,172,309 of non-FAC recoverable purchase power expense. That is a 38,272,526% variance over the course of 3 years. This volatility is driven by the commodity market exposure that is inherent in the peaking unit equivalent calculation because the cost of the hypothetical peaking unit equivalent is based on the lowest hourly natural gas price at the Columbia Gas Appalachian pricing point and an arbitrary heat rate compared to the commodity price of the marginal supply resource[9] in PJM's hourly spot energy market. During the period studied the price of energy in PJM's real time spot energy market ranged from a low of -$230/MWh to a high of $1,839/MWh. These extreme price variations coupled with the variability of the Company's hourly generation resource supply vs. load demand position creates a volatile benchmark for capping the amount of purchase power expense that can be included for recovery in the Company's FAC.

This type of unpredictable, volatile, and significant operating expense is the very definition of what should be tracked so that customers do not win or lose on this cost of service; but rather pay only what was incurred by the Company to serve customers, not a dollar more or less.

[8] January 2014 – February 2017

[9] The marginal resource in PJM is generally a natural gas combustion turbine, but can be any resource in PJM's hourly energy markets.

Q. HAS THE COMPANY PROPOSED THIS TYPE OF RECOVERY IN PREVIOUS PROCEEDINGS FOR THE FAC PURCHASE POWER LIMITATION EXPENSE?

A. Yes, in Case No. 2014-00396, the Company proposed to collect all FAC Purchase Power Limitation expense through Tariff PPA. In its final order in that proceeding the Commission denied this recovery and stated the following:

> *"Kentucky Power has not shown that the amounts of these excluded purchased power costs are volatile to the point of requiring this method of recovery. In addition, the Commission notes that there would be numerous administrative issues involved in establishing periodic proceedings to review and approve or deny these costs. The Commission believes these costs are more appropriately recoverable through base rates and will not approve this portion of the Settlement."*

The Company's proposal in this case conforms to the Commission's guidance on this issue in past cases. The Company's proposal to include an adjusted level of purchase power limitation expense in its base rate cost of service and track the differences between that level and the volatile, actual expense is reasonable and equitable to both customers and the Company. Moreover, this method does not add any significant administrative burden as it is similar to other tracking mechanisms utilized the by the Company. If this expense item is not tracked through the purchase power adjustment, the Company stands to profit from or lose on an item that should be a dollar for dollar pass-through to customers as a cost of serving them, due to the extreme volatility and materiality of the FAC Purchase Power Limitation expense.

Q. IS THE COMPANY PROPOSING ANY CHANGE TO THE CALCULATION OF THE FAC PURCHASED POWER LIMITATION?

A. Yes. The Company is proposing to change the methodology for calculating the cost of the peaking unit equivalent used in the determining the FAC Purchased Power

Limitation. The Company's proposed change results in a peaking unit equivalent cost that more accurately reflects the cost of a hypothetical combustion turbine.

Q. PLEASE DESCRIBE HOW THE COST OF THE PEAKING UNIT EQUIVALENT IS CALCULATED.

A. Currently, the cost of the peaking unit equivalent is calculated solely by multiplying the lowest hourly daily gas price at the Columbia Gas Appalachian pricing point (in $/MMBtu) by a 10,400 heat rate (10,800 for June – August), divided by 1,000). For example, a gas price of $3/MMBtu results in a peaking unit equivalent cost of $31.2/MWh [(3*10,400)/1000 = 31.2]. If the peaking unit equivalent is the highest cost unit in that hour[10], the FAC Purchased Power Limitation limits recovery of purchased power costs through the FAC to $31.2/MWh. To the extent the expense arising from this operation of the FAC Purchased Power Limitation, which is controlled by factors outside the Company's control, is not included in base rates, the Company is forced to absorb the expense.

Q. WHAT CHANGES TO THE PEAKING UNIT EQUIVALENT CALCULATION IS THE COMPANY PROPOSING IN THIS PROCEEDING?

A. The Company proposes to include the following operating costs in calculation of the cost of the peaking unit equivalent:

- Unit startup costs
- The cost of firm natural gas service
- Variable O&M expense

[10] The hourly peaking unit equivalent cost calculation compares the hypothetical peaking unit to the Company's other generating units and uses the highest cost unit for the FAC Purchased Power Limitation calculation. The hypothetical peaking unit is often the highest cost unit.

Q. WHY SHOULD THESE COSTS BE INCLUDED IN THE PEAKING UNIT EQUIVALENT COST CALCULATION?

A. All of these costs the Company is proposing to include are costs that would be incurred to operate an actual natural gas combustion turbine generating unit (CT). The peaking unit equivalent cost calculation seeks to mimic the costs of operating an actual CT because the Company does not own a real CT for the purposes of calculating the FAC Purchased Power Limitation.

CT startup costs include start up fuel consumed, station power requirements and start up maintenance and labor; and are incurred when bringing a CT online but prior to the unit generating power. These are real costs that the hypothetical CT would incur in order to generate electricity and should be included in the peaking unit equivalent cost calculation.

In order to be available to generate electricity, a CT needs to have access to natural gas which is contracted for on either a non-firm or firm basis. Firm gas service means that the unit has reserved a portion of the capacity in the pipeline making gas always available for use in generating electricity. Since the hypothetical CT used in the peaking unit equivalent cost calculation can be "dispatched" any day of the year, it requires firm gas service. Because this is a cost that an actual CT would incur to provide the service presumed for the hypothetical CT, it should be included in the peaking unit equivalent cost calculation.

Finally, Variable O&M expense associated with operating the hypothetical CT should also be included in the peaking unit equivalent cost calculation because these expenses are necessary to generate electricity at a CT.

Q. PLEASE QUANTIFY THE IMPACT ON THE PEAKING UNIT EQUIVALENT COST CALCULATION FROM THESE PROPOSED CHANGES.

A. Based on the Company's experience and information available regarding costs associated with combustion turbines, the startup costs, variable O&M, and firm gas components combine to add between $38 - $39/MWh to the peaking unit equivalent cost calculation depending on the month of the year. The details behind this calculation can be found in Exhibit AEV 8.

(c) Gains and Losses from Incidental Gas Sales

Q. WHY IS THE COMPANY ALSO PROPOSING TO TRACK GAINS AND LOSSES FROM INCIDENTAL GAS SALES THROUGH TARIFF PPA?

A. Like PJM LSE OATT charges and credits and FAC Purchased Power Limitation expenses, gains and losses from the incidental sales of natural gas that the Company had purchased for use at Big Sandy Unit 1, but could not use or store, are highly volatile and largely outside of the Company's control. Additional information about the gains and losses from incidental gas sales is included in the testimony of Company Witness Rogness.

Q. IS THE COMPANY PROPOSING ADDITIONAL CHANGES TO TARIFF PPA IN THIS PROCEEDING?

A. Yes. In addition to tracking and recovering the difference between the costs described above, and the amount of those costs included in base rates, the Company is proposing to change the structure of the Power Purchase Adjustment itself from a monthly adjusting surcharge to an annually updated surcharge. The Company also proposes to change the rate structure from a percentage of revenue charge to a structure that includes a per-kWh

Calculation of Proposed Peaking Unit Equivalent Cost Calculation Adjustment

	Firm Gas Adjustment Calculation										
	$/MMBtu		Heat Rate	$/MWh		Startup Costs $/MWh		Variable O&M $/MWh		Total $/MWh Adjustment	
January	$	0.5181	10,400	$	5.39	$	30.00	$	3.48	$	38.87
February	$	0.5181	10,400	$	5.39	$	30.00	$	3.48	$	38.87
March	$	0.5181	10,400	$	5.39	$	30.00	$	3.48	$	38.87
April	$	0.4569	10,400	$	4.75	$	30.00	$	3.48	$	38.23
May	$	0.4569	10,400	$	4.75	$	30.00	$	3.48	$	38.23
June	$	0.4569	10,800	$	4.93	$	30.00	$	3.48	$	38.41
July	$	0.4569	10,800	$	4.93	$	30.00	$	3.48	$	38.41
August	$	0.4569	10,800	$	4.93	$	30.00	$	3.48	$	38.41
September	$	0.4569	10,400	$	4.75	$	30.00	$	3.48	$	38.23
October	$	0.4569	10,400	$	4.75	$	30.00	$	3.48	$	38.23
November	$	0.5181	10,400	$	5.39	$	30.00	$	3.48	$	38.87
December	$	0.5181	10,400	$	5.39	$	30.00	$	3.48	$	38.87

Proposed new Peaking Unit Equivalent cost calculation = (Daily Gas Price * Heat Rate/1000) + Total $/MWh Adjustment

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

DATA REQUEST

PH_2 Regarding the peaking unit equivalent and start-up cost calculation. For each month in the review period, explain how many times each month the hypothetical combustion turbine was run, the length of time the hypothetical turbine was run after each start, the basis of variable operation and maintenance start-up costs, and how the start-up cost is calculated.

RESPONSE

The peaking unit equivalent value is a formula derived amount sanctioned by the Commission to limit purchased power recovery through the FAC. It is not intended to simulate the dispatch of a combustion turbine unit. Rather, as the Commission explained in its October 3, 2002 Order in Case No. 2000-00495-B it is a "proxy" used by Kentucky Power under certain circumstances "to calculate the level of non-economy [and non-forced outage] purchased power costs to flow through its FAC …."[1][1] The proxy nature of the calculation is underscored by the 75 percent threshold for consideration of the peaking unit equivalent in connection with the Company's purchased power costs:

> When a power purchase occurs during an expense month, AEP will determine the average daily market price for that month. It will then determine the lowest daily market price for gas for the hypothetical turbine during that month and compare that price to its actual average purchased energy cost for internal uses for the same month. ***If the actual average purchased energy cost for internal use for the month is 75 percent or less*** of the lowest daily market price for gas for the hypothetical gas turbine during the same month, AEP will consider this cost as the fuel cost for these purchases. ***If the actual average purchased energy cost for internal use is greater than 75 percent of the lowest daily market price for gas for the hypothetical gas turbine***, then AEP will compare its average purchased energy cost for internal uses with the market price for gas for the hypothetical turbine for each day of the month and exclude for FAC purposes any of the actual purchased energy costs that exceed the daily gas market price.[2][2]

KIUC HEARING
EXHIBIT 2

This 75 percent threshold renders any effort to characterize the application of the peaking unit equivalent as a simulation of the actual operation of the hypothetical turbine both inapposite and inaccurate. In addition, any simulation of the dispatch of the hypothetical turbine would need to consider other factors such as, but not limited to, the availability of gas for the unit, pipeline capability, as well as the engineering and operational characteristics and requisites for the unit. Among the engineering and operational characteristics and requisites for the unit include those real world times the unit would dispatch and for how long. For example, during the review period, the peaking unit equivalent calculation capped costs for the 9 AM hour on May 4 and then again from 3 PM through 7 PM. In a real-world simulation would the unit shut down during the period between 10 AM and 3 PM? What actions affecting dispatch would be required to avoid deleterious effects of multiple starts of the unit?

As a result, there is no analysis to simulate how many times a unit was run or the length of time it was run after each start. In an effort to be responsive to the data request please see the table below and KPCO_R_KPSC_PH_2_Attachment2 for the supporting calculations made on data provided in the Company's response to Staff 1-16.

	May	June	July	August	September	October
Total Number of Hours when the PUE Calculation Resulted in a Reduction in Purchased Power Costs	10	0	2	58	10	11
Greatest Number of Consecutive Hours when the PUE Calculation Resulted in a Reduction in Purchased Power Costs	4	0	2	5	5	3

Please also see KPCO_R_KPSC_PH_2_Attachment1 for the basis of the variable operation and maintenance cost and the startup cost. It previously was filed as Exhibit AEV-8 to Company Witness Vaughan's Direct Testimony in Case No. 2017-00179.

[1] Order, *In the Matter Of: An Examination By The Public Service Commission Of The Application Of The Fuel Adjustment Clause Of American Electric Power Company From May 1, 2001 to October 1, 2001* at 3 (Ky. P.S.C. October 3, 2002).

[2] *Id.* at 2-3 (emphasis supplied).

Witness: Jason M. Stegall

Exhibit AEV 8
Calculation of Proposed Peaking Unit Equivalent Cost Adder

	Firm Gas Adder Calculation					
	$/MMBtu	Heat Rate	$/MWh Adder	Startup Costs $/MWh	Variable O&M $/MWh	Total $/MWh Adder
January	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
February	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
March	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
April	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
May	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
June	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
July	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
August	$ 0.4569	10,800	$ 4.93	$ 30.00	$ 3.48	$ 38.41
September	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
October	$ 0.4569	10,400	$ 4.75	$ 30.00	$ 3.48	$ 38.23
November	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87
December	$ 0.5181	10,400	$ 5.39	$ 30.00	$ 3.48	$ 38.87

Firm Reservation Rate, per Big Sandy Agreement ($.20/MMBtu)
Firm Surcharges, as stated in TCO tariff ($.0545/MMBtu)
Firm Transportation Commodity Rate ($0.0104/MMBtu)
Transportation Retainage, as stated in TCO tariff (1.893% or ~$0.058 on $3 gas)
Park and Lend Rate, as stated in the TCO tariff ($0.1939 winter and $0.1327 summer)
FERC Annual Charge Adjustment (ACA) ($0.0013/MMbtu)

Ceredo Combustion Turbines
Historical Variable O&M Costs

Year	Month	Unitname	MWH	Total Accounting Rate	Fuel Rate 151	Handling Rate 152
2013	January	Ceredo	1,224	65.28	13.62	0.45
2013	February	Ceredo	306	66.92	15.56	2.06
2013	March	Ceredo	728	66.42	16.83	1.84
2013	April	Ceredo	0	0	0	0
2013	May	Ceredo	662	74.83	15.23	3.90
2013	June	Ceredo	86	116.04	12.73	6.11
2013	July	Ceredo	2,983	59.18	15.25	0.27
2013	August	Ceredo	0	0	0	0
2013	September	Ceredo	645	54.67	13.79	1.36
2013	October	Ceredo	0	0	0	0
2013	November	Ceredo	100	184.66	24.79	8.04
2013	December	Ceredo	697	69.97	16.24	2.16
2014	January	Ceredo	11,707	27.35	27.24	0.12
2014	February	Ceredo	8,880	33.81	33.62	0.20
2014	March	Ceredo	6,411	28.58	28.33	0.25
2014	April	Ceredo	510	21.76	19.48	2.28
2014	May	Ceredo	876	18.61	17.38	1.24
2014	June	Ceredo	88	2,223	1,067	1,157
2014	July	Ceredo	155	2,744	2,057	687
2014	August	Ceredo	366	6,402	5,545	857
2014	September	Ceredo	70	567	567	0
2014	October	Ceredo	501	7,129	7,367	-238
2014	November	Ceredo	0	0	0	0
2014	December	Ceredo	507	14.96	13.78	1.18
2015	January	Ceredo	1,764	15.26	14.69	0.56
2015	February	Ceredo	3,405	16.53	16.21	0.31
2015	March	Ceredo	909	14.43	13.76	0.67
2015	April	Ceredo	0	0.00	0.00	0.00
2015	May	Ceredo	5,224	11.32	11.21	0.11
2015	June	Ceredo	3,134	9.36	9.17	0.19
2015	July	Ceredo	2,994	11.39	11.21	0.18
2015	August	Ceredo	1,347	11.07	10.55	0.52
2015	September	Ceredo	1,647	10.65	10.09	0.56
2015	October	Ceredo	0	0.00	0.00	0.00
2015	November	Ceredo	395	9.63	7.74	1.90
2015	December	Ceredo	0	0.00	0.00	0.00

58,321

O&M Cost / MWH	VOM Cost
6.45	7,895
5.92	1,812
8.94	6,508
0.00	-
7.17	4,747
40.36	3,471
1.30	3,878
0.00	-
6.71	4,328
0.00	-
9.31	931
7.51	5,234
0.72	8,429
1.10	9,768
0.81	5,193
23.62	12,044
5.07	4,441
137.08	12,063
49.90	7,734
25.06	9,172
246.72	17,270
26.03	13,039
0.00	-
21.54	10,918
5.51	9,720
1.20	4,086
3.06	2,777
0.00	-
1.16	6,060
2.00	6,268
2.09	6,242
3.71	4,991
7.46	12,287
0.00	-
4.19	1,653
0.00	-

3.48 Avg VOM $/MWh	202,956

Ceredo 1	Date	Start Cost						
	11/4/2016	$ 2,940.67						
	11/5/2016	$ 2,932.65						
	11/6/2016	$ 2,932.65		$ 3,005.84	Avg			
	11/4/2016	$ 2,940.67				min run	MW	
	11/5/2016	$ 2,932.65	use	3000		1		100
	11/6/2016	$ 2,932.65						
	11/7/2016	$ 2,932.65						
	11/8/2016	$ 2,950.27						
	11/9/2016	$ 2,953.19						
	11/10/2016	$ 2,945.89						
	11/11/2016	$ 2,934.22						
	11/12/2016	$ 2,929.11						
	11/13/2016	$ 2,929.11						
	11/14/2016	$ 2,929.11						
	11/15/2016	$ 2,945.89						
	11/16/2016	$ 2,962.68						
	11/17/2016	$ 2,967.78						
	11/18/2016	$ 2,949.54						
	11/19/2016	$ 2,970.70						
	11/20/2016	$ 2,970.70						
	11/21/2016	$ 2,970.70						
	11/22/2016	$ 2,988.94						
	11/23/2016	$ 2,983.84						
	11/24/2016	$ 2,981.65						
	11/25/2016	$ 2,981.65						
	11/26/2016	$ 2,981.65						
	11/27/2016	$ 2,981.65						
	11/28/2016	$ 2,981.65						
	11/29/2016	$ 2,993.32						
	11/30/2016	$ 3,001.35						
	12/1/2016	$ 3,024.37						
	12/2/2016	$ 3,030.21						
	12/3/2016	$ 3,028.02						
	12/4/2016	$ 3,028.02						
	12/5/2016	$ 3,028.02						
	12/6/2016	$ 3,044.07						
	12/7/2016	$ 3,056.47						
	12/8/2016	$ 3,060.85						
	12/9/2016	$ 3,056.47						
	12/10/2016	$ 3,063.04						
	12/11/2016	$ 3,063.04						
	12/12/2016	$ 3,063.04						
	12/13/2016	$ 3,049.18						
	12/14/2016	$ 3,049.18						
	12/15/2016	$ 3,044.80						

12/16/2016	$	3,048.45
12/17/2016	$	3,034.58
12/18/2016	$	3,034.58
12/19/2016	$	3,034.58
12/20/2016	$	3,047.72
12/21/2016	$	3,032.39
12/22/2016	$	3,044.80
12/23/2016	$	3,047.72
12/24/2016	$	3,048.45
12/25/2016	$	3,048.45
12/26/2016	$	3,048.45
12/27/2016	$	3,048.45
12/28/2016	$	3,052.82
12/29/2016	$	3,045.53
12/30/2016	$	3,049.91
12/31/2016	$	3,049.91
1/1/2017	$	3,045.38
1/2/2017	$	3,045.38
1/3/2017	$	3,045.38
1/4/2017	$	3,032.25
1/5/2017	$	3,033.71
1/6/2017	$	3,027.14
1/7/2017	$	3,030.79
1/8/2017	$	3,030.79
1/9/2017	$	3,030.79
1/10/2017	$	3,011.82
1/11/2017	$	3,019.85
1/12/2017	$	3,022.77
1/13/2017	$	3,029.33
1/14/2017	$	3,030.79
1/15/2017	$	3,030.79
1/16/2017	$	3,030.79
1/17/2017	$	3,030.79
1/18/2017	$	3,027.87
1/19/2017	$	3,022.04
1/20/2017	$	3,022.04
1/21/2017	$	3,018.39
1/22/2017	$	3,018.39
1/23/2017	$	3,018.39
1/24/2017	$	3,015.47
1/25/2017	$	3,022.77
1/26/2017	$	3,023.50
1/27/2017	$	3,034.44
1/28/2017	$	3,023.50
1/29/2017	$	3,023.50
1/30/2017	$	3,023.50
1/31/2017	$	3,019.12

2/1/2017	$	3,015.47
2/2/2017	$	3,015.47
2/3/2017	$	3,014.74
2/4/2017	$	3,007.44
2/5/2017	$	3,007.44
2/6/2017	$	3,007.44
2/7/2017	$	3,000.88
2/8/2017	$	3,008.90
2/9/2017	$	3,010.36
2/10/2017	$	3,014.01
2/11/2017	$	2,998.69
2/12/2017	$	2,998.69
2/13/2017	$	2,998.69
2/14/2017	$	3,001.61
2/15/2017	$	2,995.04
2/16/2017	$	3,001.61
2/17/2017	$	2,992.85
2/18/2017	$	2,981.91
2/19/2017	$	2,981.91
2/20/2017	$	2,981.91
2/21/2017	$	2,981.91
2/22/2017	$	2,965.13
2/23/2017	$	2,963.67
2/24/2017	$	2,972.42
2/25/2017	$	2,964.40
2/26/2017	$	2,964.40
2/27/2017	$	2,964.40
2/28/2017	$	2,965.13
3/1/2017	$	2,971.29
3/2/2017	$	2,976.40
3/3/2017	$	2,974.94
3/4/2017	$	2,972.02
3/5/2017	$	2,972.02
3/6/2017	$	2,972.02
3/7/2017	$	2,984.42
3/8/2017	$	2,979.31
3/9/2017	$	2,986.61
3/10/2017	$	2,998.29
3/11/2017	$	3,009.23
3/12/2017	$	2,998.29
3/13/2017	$	3,009.23
3/14/2017	$	3,016.53
3/15/2017	$	3,017.99
3/16/2017	$	3,014.34
3/17/2017	$	3,000.47
3/18/2017	$	2,997.56
3/19/2017	$	2,997.56

3/20/2017	$	2,997.56
3/21/2017	$	3,003.39
3/22/2017	$	3,013.61
3/23/2017	$	3,008.50
3/24/2017	$	3,000.47
3/25/2017	$	2,998.29
3/26/2017	$	2,998.29
3/27/2017	$	2,998.29
3/28/2017	$	3,008.50
3/29/2017	$	3,005.58
3/30/2017	$	3,011.42
3/31/2017	$	3,012.15
4/1/2017	$	3,011.73
4/2/2017	$	3,011.73
4/3/2017	$	3,011.73
4/4/2017	$	3,008.81
4/5/2017	$	3,015.38
4/6/2017	$	3,024.86
4/7/2017	$	3,024.86
4/8/2017	$	3,021.21
4/9/2017	$	3,021.21
4/10/2017	$	3,021.21
4/11/2017	$	3,019.75
4/12/2017	$	3,012.46
4/13/2017	$	3,013.19
4/14/2017	$	3,013.92
4/15/2017	$	3,013.92
4/16/2017	$	3,013.92
4/17/2017	$	3,013.92
4/18/2017	$	3,016.11
4/19/2017	$	3,012.46
4/20/2017	$	3,016.11
4/21/2017	$	3,012.46
4/22/2017	$	3,008.81
4/23/2017	$	3,008.81
4/24/2017	$	3,008.81
4/25/2017	$	3,004.43
4/26/2017	$	3,002.97
4/27/2017	$	3,005.16
4/28/2017	$	3,005.16
4/29/2017	$	3,013.92
4/30/2017	$	3,013.92
5/1/2017	$	3,003.35

$/MWh start cost
30

KIUC HEARING EXHIBIT 3

	STEP 1 & 3			STEP 2								
	(3)	(3a)	(5a)	(6)	(7)	(8)	(9)	(10)	(11)			(12)
DAY AND HOUR ENDING	PURCHASES ASSIGNED TO INTERNAL LOAD (MWh)	MARGINAL LOSSES	DISPATCHED GENERATION	NET AVAILABLE GENERATION RESOURCES	INTERNAL LOAD	PURCHASES DUE TO DEFICIENCY (Step 2)	PURCHASES DUE TO F.O. DEFICIENCY (MIN STEP 1 OR 2)	Net Position = Gen + losses + purchases - Load	MAX FO VOLUME REQUIRING REPLACEMENT POWER			AVERAGE PRICE OF PURCHASED POWER
	INPUT FROM KP Hourly Purch Alloc Tab	INPUT FROM PT	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER	MAX ((7)-(6),0)	MIN (5),(8)	(3) + (3a) + (5a) - (7)	Mitchell 1	Mitchell 2	BS 1	INPUT FROM PowerTracker
BIG SANDY U1									0	0	0	
MITCHELL UNIT 1												
MITCHELL UNIT 2												
10/10/2022 06	622	10	-	-	632	632	-	-	-	-	-	$ 65.360
10/10/2022 07	683	10	-	-	693	693	-	-	-	-	-	$ 84.332
10/10/2022 08	724	10	-	-	734	734	-	-	-	-	-	$ 96.364
10/10/2022 09	730	10	-	-	740	740	-	-	-	-	-	$ 83.160
10/10/2022 10	713	9	-	-	722	722	-	-	-	-	-	$ 75.265
10/10/2022 11	681	9	-	-	690	690	-	-	-	-	-	$ 73.797
10/10/2022 12	643	9	-	-	651	651	-	-	-	-	-	$ 71.148
10/10/2022 13	613	8	-	-	621	621	-	-	-	-	-	$ 70.650
10/10/2022 14	590	8	-	-	598	598	-	-	-	-	-	$ 70.070
10/10/2022 15	585	8	-	-	592	592	-	-	-	-	-	$ 66.540
10/10/2022 16	591	7	-	-	599	599	-	-	-	-	-	$ 67.652
10/10/2022 17	588	7	-	-	595	595	-	-	-	-	-	$ 75.030
10/10/2022 18	581	8	-	-	589	589	-	-	-	-	-	$ 85.570
10/10/2022 19	593	8	-	-	601	601	-	-	-	-	-	$ 94.791
10/10/2022 20	611	9	-	-	620	620	-	-	-	-	-	$ 107.040
10/10/2022 21	621	8	-	-	630	630	-	-	-	-	-	$ 82.110
10/10/2022 22	601	8	-	-	609	609	-	-	-	-	-	$ 73.399
10/10/2022 23	577	9	-	-	586	586	-	-	-	-	-	$ 63.278
10/11/2022 00	556	10	-	-	565	565	-	-	-	-	-	$ 59.018
10/11/2022 01	540	10	-	-	550	550	-	-	-	-	-	$ 46.596
10/11/2022 02	545	11	-	-	556	556	-	-	-	-	-	$ 43.698
10/11/2022 03	552	11	-	-	562	562	-	-	-	-	-	$ 40.171
10/11/2022 04	559	11	-	-	569	569	-	-	-	-	-	$ 39.715
10/11/2022 05	576	11	-	-	586	586	-	-	-	-	-	$ 45.795

1

Download Mkt Gen Snapshot for KP units

Need to reduce RP1KP & RP2KP settle depend cap to 15%
Need to reduce ML1KP & ML2KP settle depend cap to 50%

Reduce RP1KP & RP2KP settle depend cap to 15%
Reduce ML1KP & ML2KP settle depend cap to 50%

Entity Name	Date/Hour	Control Mode	Net Gen	Capability High Limit	Settle High Limit	Dependable Capability	Settle Dep Capability	blank	% Owned	Set High Adj	Set Dep Adj	Cap High Adj
89040101-Big Sandy 1	10/10/2022 6:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 7:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 8:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 9:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 10:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 11:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 12:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 13:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 14:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 15:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 16:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 17:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 18:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 19:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 20:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 21:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 22:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/10/2022 23:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 0:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 1:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 2:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 3:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 4:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	10/11/2022 5:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
ML1KP-Mitchell 1 KP	10/10/2022 6:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 7:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 8:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 9:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 10:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 11:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 12:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 13:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 14:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 15:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 16:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 17:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 18:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 19:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 20:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 21:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 22:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/10/2022 23:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 0:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 1:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 2:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 3:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 4:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML1KP-Mitchell 1 KP	10/11/2022 5:00	OFFLINE	0	0	0	0	770		0.50	0	385	0
ML2KP-Mitchell 2 KP	10/10/2022 6:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 7:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 8:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 9:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 10:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 11:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 12:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 13:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 14:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 15:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 16:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 17:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 18:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 19:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 20:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 21:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 22:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/10/2022 23:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 0:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 1:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 2:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 3:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 4:00	OFFLINE	0	0	0	0	680		0.50	0	340	0
ML2KP-Mitchell 2 KP	10/11/2022 5:00	OFFLINE	0	0	0	0	680		0.50	0	340	0

2

Download Mkt Gen Snapshot for KP units

Need to reduce RP1KP & RP2KP settle depend cap to 15%
Need to reduce ML1KP & ML2KP settle depend cap to 50%

Reduce RP1KP & RP2KP settle depend cap to 15%
Reduce ML1KP & ML2KP settle depend cap to 50%

Entity Name	Date/Hour	Control Mode	Net Gen	Capability High Limit	Settle High Limit	Dependable Capability	Settle Dep Capability	blank	% Owned	Set High Adj	Set Dep Adj	Cap High Adj
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 6:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 7:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 8:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 9:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 10:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 11:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 12:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 13:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 14:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 15:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 16:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 17:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 18:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 19:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 20:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 21:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 22:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/10/2022 23:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 0:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 1:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 2:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 3:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 4:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP1KPAEG-Rockport 1 KP AEG	10/11/2022 5:00	OFFLINE	0	0	0	0	1266		0.15	0	189.9	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 6:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 7:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 8:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 9:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 10:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 11:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 12:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 13:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 14:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 15:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 16:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 17:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 18:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 19:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 20:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 21:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 22:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/10/2022 23:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 0:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 1:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 2:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 3:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 4:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0
RP2KPAEG-Rockport 2 KP AEG	10/11/2022 5:00	OFFLINE	0	0	0	0	1300		0.15	0	195	0

3

Kentucky Power Purchase Allocation
October-22

Day/Hour Ending	Purchases Assigned to Internal Load Not Due to Forced Outage MW	$/ MWh of Purchases allocated to Internal Load	Daily Gas Price	Peaking Unit Equivalent $/MWh	Big Sandy 1 Generation Cost $/MWh	Mitchell Unit 1 KP Generation Cost $/MWh	Mitchell Unit 2 KP Generation Cost $/MWh	Rockport 1 KP Generation Cost $/MWh	Rockport 2 KP Generation Cost $/MWh	Highest of PUE or Generation Cost $/MWh	Difference in $/MWh	Total Difference in PUE & Purchase Price $
					Generation and Fuel Cost data from NER							
					MW Generated	MW Generated	MW Generated	MW Generated	MW Generated			
					0	0	0	0	0			
				Update for Jun Aug	$504,601.20	$0.00	$0.00	$84,666.22	$120,068.38			
10/10/2022 06	622.12	65.360	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 07	682.92	84.332	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 08	724.36	96.364	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	3.915531107	2,836.26
10/10/2022 09	729.99	83.160	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 10	713.11	75.265	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 11	680.53	73.797	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 12	642.67	71.148	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 13	612.65	70.650	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 14	590.26	70.070	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 15	584.79	66.540	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 16	591.20	67.652	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 17	587.53	75.030	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 18	581.19	85.570	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 19	593.29	94.791	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	2.343126414	1,390.15
10/10/2022 20	610.80	107.040	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	14.59150172	8,912.42
10/10/2022 21	621.45	82.110	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 22	601.09	73.399	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/10/2022 23	576.95	63.278	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/11/2022 00	555.57	59.018	$5.67	92.448	0.000	0.000	0.000	0.000	0.000	92.448	0	0.00
10/11/2022 01	539.84	46.596	$5.61	91.824	0.000	0.000	0.000	0.000	0.000	91.824	0	0.00
10/11/2022 02	545.26	43.698	$5.61	91.824	0.000	0.000	0.000	0.000	0.000	91.824	0	0.00
10/11/2022 03	551.66	40.171	$5.61	91.824	0.000	0.000	0.000	0.000	0.000	91.824	0	0.00
10/11/2022 04	558.61	39.715	$5.61	91.824	0.000	0.000	0.000	0.000	0.000	91.824	0	0.00
10/11/2022 05	575.84	45.795	$5.61	91.824	0.000	0.000	0.000	0.000	0.000	91.824	0	0.00

4

KIUC HEARING
EXHIBIT 4

	STEP 1 & 3		STEP 2									
	(3)	(3a)	(5a)	(6)	(7)	(8)	(9)	(10)	(11)			(12)
DAY AND HOUR ENDING	PURCHASES ASSIGNED TO INTERNAL LOAD (MWh)	MARGINAL LOSSES	DISPATCHED GENERATION	NET AVAILABLE GENERATION RESOURCES	INTERNAL LOAD	PURCHASES DUE TO DEFICIENCY (Step 2)	PURCHASES DUE TO F.O. DEFICIENCY (MIN STEP 1 OR 2)	Net Position = Gen + losses + purchases - Load	MAX FO VOLUME REQUIRING REPLACEMENT POWER			AVERAGE PRICE OF PURCHASED POWER
	INPUT FROM KP Hourly Purch Alloc Tab	INPUT FROM PT	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER	INPUT FROM POWER TRACKER	MAX [(7)-(6),0]	MIN (5),(8)	(3) + (3a) + (5a) - (7)	Mitchell 1	Mitchell 2	BS 1	INPUT FROM PowerTracker
THERE WERE NO									140,220	66,568	66,824	
THERE WAS 1												
THERE WERE NO												
06/02/2022 03	123	8	413	934	544	-	-	-	-	-	-	$ 55.138
06/02/2022 04	115	7	411	905	534	-	-	-	-	-	-	$ 53.148
06/02/2022 05	108	7	411	905	527	-	-	-	-	-	-	$ 51.510
06/02/2022 06	113	7	417	934	537	-	-	-	-	-	-	$ 54.170
06/02/2022 07	102	8	444	960	554	-	-	-	-	-	-	$ 61.280
06/02/2022 08	148	8	421	952	577	-	-	-	-	-	-	$ 65.580
06/02/2022 09	180	8	421	951	609	-	-	-	-	-	-	$ 69.470
06/02/2022 10	223	9	413	948	645	-	-	-	-	-	-	$ 81.437
06/02/2022 11	251	10	421	934	682	-	-	-	-	-	-	$ 97.250
06/02/2022 12	298	11	412	919	721	-	-	-	-	-	-	$ 99.423
06/02/2022 13	333	12	412	899	757	-	-	-	-	-	-	$ 99.779
06/02/2022 14	345	13	431	930	788	-	-	-	-	-	-	$ 113.788
06/02/2022 15	361	13	435	945	809	-	-	-	-	-	-	$ 114.067
06/02/2022 16	294	14	504	960	811	-	-	-	-	-	-	$ 107.860
06/02/2022 17	344	13	444	960	802	-	-	-	-	-	-	$ 104.245
06/02/2022 18	350	13	417	941	780	-	-	-	-	-	-	$ 97.676
06/02/2022 19	327	13	415	938	754	-	-	-	-	-	-	$ 100.107
06/02/2022 20	296	12	418	959	725	-	-	-	-	-	-	$ 93.572
06/02/2022 21	279	11	413	903	703	-	-	-	-	-	-	$ 89.539
06/02/2022 22	256	10	420	919	686	-	-	-	-	-	-	$ 89.669
06/02/2022 23	144	9	493	939	646	-	-	-	-	-	-	$ 70.760
06/03/2022 00	60	8	534	897	603	-	-	-	-	-	-	$ 65.330
06/03/2022 01	52	8	504	672	563	-	-	-	-	-	-	$ 64.180
06/03/2022 02	65	8	461	644	535	-	-	-	-	-	-	$ 57.580

1

Download Mkt Gen Snapshot for KP units

Need to reduce RP1KP & RP2KP settle depend cap to 15%
Need to reduce ML1KP & ML2KP settle depend cap to 50%

Reduce RP1KP & RP2KP settle depend cap to 15%
Reduce ML1KP & ML2KP settle depend cap to 50%

Entity Name	Date/Hour	Control Mode	Net Gen	Capability High Limit	Settle High Limit	Dependable Capability	Settle Dep Capability	blank	% Owned	Set High Adj	Set Dep Adj	Cap High Adj
89040101-Big Sandy 1	6/2/2022 3:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 4:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 5:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 6:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 7:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 8:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 9:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 10:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 11:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 12:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 13:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 14:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 15:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 16:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 17:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 18:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 19:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 20:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 21:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 22:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/2/2022 23:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/3/2022 0:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/3/2022 1:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
89040101-Big Sandy 1	6/3/2022 2:00	OFFLINE	0	0	0	0	295		1.00	0	295	0
ML1KP-Mitchell 1 KP	6/2/2022 3:00	DISPATCHABLE	186.379	729	729	729	770		0.50	364.5	385	364.5
ML1KP-Mitchell 1 KP	6/2/2022 4:00	DISPATCHABLE	185.6265	767	767	767	770		0.50	383.5	385	383.5
ML1KP-Mitchell 1 KP	6/2/2022 5:00	DISPATCHABLE	185.7835	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 6:00	DISPATCHABLE	186.0995	767	767	767	770		0.50	383.5	385	383.5
ML1KP-Mitchell 1 KP	6/2/2022 7:00	DISPATCHABLE	187.02	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 8:00	DISPATCHABLE	185.9375	764	764	764	770		0.50	382	385	382
ML1KP-Mitchell 1 KP	6/2/2022 9:00	DISPATCHABLE	189.838	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 10:00	DISPATCHABLE	186.5455	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 11:00	DISPATCHABLE	190.4695	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 12:00	DISPATCHABLE	186.328	766	766	766	770		0.50	383	385	383
ML1KP-Mitchell 1 KP	6/2/2022 13:00	DISPATCHABLE	186.0215	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 14:00	DISPATCHABLE	198.294	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 15:00	DISPATCHABLE	192.221	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 16:00	DISPATCHABLE	220.0015	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 17:00	DISPATCHABLE	193.0905	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 18:00	DISPATCHABLE	186.4555	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 19:00	DISPATCHABLE	186.1215	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 20:00	DISPATCHABLE	186.2095	769	769	769	770		0.50	384.5	385	384.5
ML1KP-Mitchell 1 KP	6/2/2022 21:00	DISPATCHABLE	186.1555	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/2/2022 22:00	DISPATCHABLE	186.5505	758	758	758	770		0.50	379	385	379
ML1KP-Mitchell 1 KP	6/2/2022 23:00	DISPATCHABLE	236.37	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/3/2022 0:00	DISPATCHABLE	298.555	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/3/2022 1:00	DISPATCHABLE	300.0305	770	770	770	770		0.50	385	385	385
ML1KP-Mitchell 1 KP	6/3/2022 2:00	DISPATCHABLE	300.964	770	770	770	770		0.50	385	385	385
ML2KP-Mitchell 2 KP	6/2/2022 3:00	DISPATCHABLE	151.0105	729	790	790	735		0.50	395	367.5	364.5
ML2KP-Mitchell 2 KP	6/2/2022 4:00	DISPATCHABLE	150.4855	728	790	790	735		0.50	395	367.5	364
ML2KP-Mitchell 2 KP	6/2/2022 5:00	DISPATCHABLE	150.399	711	790	790	735		0.50	395	367.5	355.5
ML2KP-Mitchell 2 KP	6/2/2022 6:00	DISPATCHABLE	150.373	688	790	790	735		0.50	395	367.5	344
ML2KP-Mitchell 2 KP	6/2/2022 7:00	DISPATCHABLE	151.776	738	790	790	735		0.50	395	367.5	369
ML2KP-Mitchell 2 KP	6/2/2022 8:00	DISPATCHABLE	150.3665	726	790	790	735		0.50	395	367.5	363
ML2KP-Mitchell 2 KP	6/2/2022 9:00	DISPATCHABLE	154.552	743	790	790	735		0.50	395	367.5	371.5
ML2KP-Mitchell 2 KP	6/2/2022 10:00	DISPATCHABLE	151.317	743	790	790	735		0.50	395	367.5	371.5
ML2KP-Mitchell 2 KP	6/2/2022 11:00	DISPATCHABLE	155.053	743	790	790	735		0.50	395	367.5	371.5
ML2KP-Mitchell 2 KP	6/2/2022 12:00	DISPATCHABLE	150.5885	735	790	790	735		0.50	395	367.5	367.5
ML2KP-Mitchell 2 KP	6/2/2022 13:00	DISPATCHABLE	150.5765	730	730	730	739		0.50	365	369.5	365
ML2KP-Mitchell 2 KP	6/2/2022 14:00	DISPATCHABLE	156.863	790	790	790	790		0.50	395	395	395
ML2KP-Mitchell 2 KP	6/2/2022 15:00	DISPATCHABLE	157.6655	790	790	790	790		0.50	395	395	395
ML2KP-Mitchell 2 KP	6/2/2022 16:00	DISPATCHABLE	168.948	790	790	790	790		0.50	395	395	395
ML2KP-Mitchell 2 KP	6/2/2022 17:00	DISPATCHABLE	156.6275	790	790	790	790		0.50	395	395	395
ML2KP-Mitchell 2 KP	6/2/2022 18:00	DISPATCHABLE	151.064	789	789	789	790		0.50	394.5	395	394.5
ML2KP-Mitchell 2 KP	6/2/2022 19:00	DISPATCHABLE	151.0855	790	790	790	790		0.50	395	395	395
ML2KP-Mitchell 2 KP	6/2/2022 20:00	DISPATCHABLE	150.815	789	789	789	790		0.50	394.5	395	394.5
ML2KP-Mitchell 2 KP	6/2/2022 21:00	DISPATCHABLE	150.4105	698	698	698	790		0.50	349	395	349
ML2KP-Mitchell 2 KP	6/2/2022 22:00	DISPATCHABLE	151.535	737	737	737	790		0.50	368.5	395	368.5
ML2KP-Mitchell 2 KP	6/2/2022 23:00	DISPATCHABLE	150.8735	747	747	747	790		0.50	373.5	395	373.5
ML2KP-Mitchell 2 KP	6/3/2022 0:00	DISPATCHABLE	148.5815	672	672	672	790		0.50	336	395	336
ML2KP-Mitchell 2 KP	6/3/2022 1:00	FIXED	126.253	253	253	253	790		0.50	126.5	395	126.5
ML2KP-Mitchell 2 KP	6/3/2022 2:00	DISPATCHABLE	84.266	169	169	169	790		0.50	84.5	395	84.5

2

Download Mkt Gen Snapshot for KP units

Need to reduce RP1KP & RP2KP settle depend cap to 15%
Need to reduce ML1KP & ML2KP settle depend cap to 50%

Reduce RP1KP & RP2KP settle depend cap to 15%
Reduce ML1KP & ML2KP settle depend cap to 50%

Entity Name	Date/Hour	Control Mode	Net Gen	Capability High Limit	Settle High Limit	Dependable Capability	Settle Dep Capability	blank	% Owned	Set High Adj	Set Dep Adj	Cap High Adj
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 3:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 4:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 5:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 6:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 7:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 8:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 9:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 10:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 11:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 12:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 13:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 14:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 15:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 16:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 17:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 18:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 19:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 20:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 21:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 22:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/2/2022 23:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/3/2022 0:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/3/2022 1:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP1KPAEG-Rockport 1 KP AEG	6/3/2022 2:00	OFFLINE	0	0	0	0	1320		0.15	0	198	0
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 3:00	DISPATCHABLE	76.0338	1164	1164	1164	1200		0.15	174.6	180	174.6
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 4:00	DISPATCHABLE	74.967	840	840	840	1200		0.15	126	180	126
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 5:00	DISPATCHABLE	74.94	832	832	832	1200		0.15	124.8	180	124.8
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 6:00	DISPATCHABLE	80.8038	1034	1034	1034	1200		0.15	155.1	180	155.1
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 7:00	DISPATCHABLE	105.0516	1200	1200	1200	1200		0.15	180	180	180
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 8:00	DISPATCHABLE	84.918	1169	1169	1169	1200		0.15	175.35	180	175.35
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 9:00	DISPATCHABLE	76.1634	1140	1140	1140	1200		0.15	171	180	171
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 10:00	DISPATCHABLE	75.558	1121	1121	1121	1200		0.15	168.15	180	168.15
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 11:00	DISPATCHABLE	75.4644	1025	1025	1025	1200		0.15	153.75	180	153.75
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 12:00	DISPATCHABLE	75.2574	941	941	941	1200		0.15	141.15	180	141.15
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 13:00	DISPATCHABLE	75.4746	994	994	994	1200		0.15	149.1	180	149.1
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 14:00	DISPATCHABLE	75.4032	997	997	997	1200		0.15	149.55	180	149.55
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 15:00	DISPATCHABLE	84.8712	1103	1103	1103	1200		0.15	165.45	180	165.45
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 16:00	DISPATCHABLE	115.107	1200	1200	1200	1200		0.15	180	180	180
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 17:00	DISPATCHABLE	94.5174	1200	1200	1200	1200		0.15	180	180	180
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 18:00	DISPATCHABLE	79.734	1076	1076	1076	1200		0.15	161.4	180	161.4
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 19:00	DISPATCHABLE	77.4318	1052	1052	1052	1200		0.15	157.8	180	157.8
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 20:00	DISPATCHABLE	80.6652	1200	1200	1200	1200		0.15	180	180	180
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 21:00	DISPATCHABLE	76.1274	1126	1126	1126	1200		0.15	168.9	180	168.9
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 22:00	DISPATCHABLE	82.1634	1142	1142	1142	1200		0.15	171.3	180	171.3
RP2KPAEG-Rockport 2 KP AEG	6/2/2022 23:00	DISPATCHABLE	105.6228	1200	1200	1200	1200		0.15	180	180	180
RP2KPAEG-Rockport 2 KP AEG	6/3/2022 0:00	DISPATCHABLE	87.0624	1175	1175	1175	1200		0.15	176.25	180	176.25
RP2KPAEG-Rockport 2 KP AEG	6/3/2022 1:00	DISPATCHABLE	77.3472	1073	1073	1073	1200		0.15	160.95	180	160.95
RP2KPAEG-Rockport 2 KP AEG	6/3/2022 2:00	DISPATCHABLE	76.053	1160	1160	1160	1200		0.15	174	180	174

3

Kentucky Power Purchase Allocation
June-22

					Generation and Fuel Cost data from NER							
					MW Generated	MW Generated	MW Generated	MW Generated	MW Generated			
					66,824	140,220	66,568	58,003	27,950			
	Purchases Assigned to Internal Load Not Due to Forced Outage MW	$/ MWh of Purchases allocated to Internal Load	Daily Gas Price	Peaking Unit Equivalent $/MWh	Big Sandy 1 Generation Cost $/MWh	Mitchell Unit 1 KP Generation Cost $/MWh	Mitchell Unit 2 KP Generation Cost $/MWh	Rockport 1 KP Generation Cost $/MWh	Rockport 2 KP Generation Cost $/MWh	Highest of PUE or Generation Cost $/MWh	Difference in $/MWh	Total Difference in PUE & Purchase Price $
Day/Hour Ending				Update for Jun-Aug	$ 5,142,690	$ 3,478,911	$ 1,616,779	$ 2,059,676	$ 1,037,164			
06/02/2022 03	122.61	55.138	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 04	115.39	53.148	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 05	108.44	51.510	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 06	112.83	54.170	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 07	102.21	61.280	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 08	148.21	65.580	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 09	179.66	69.470	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 10	222.54	81.437	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 11	251.39	97.250	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 12	298.11	99.423	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 13	333.43	99.779	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 14	345.31	113.788	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 15	360.87	114.067	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 16	293.68	107.860	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 17	344.43	104.245	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 18	349.70	97.676	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 19	327.12	100.107	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 20	295.55	93.572	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 21	279.02	89.539	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 22	255.74	89.669	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/02/2022 23	143.82	70.760	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/03/2022 00	60.30	65.330	$8.110	121.068	76.959	24.810	24.288	35.510	37.108	121.068	0.00	0.00
06/03/2022 01	51.56	64.180	$7.980	119.664	76.959	24.810	24.288	35.510	37.108	119.664	0.00	0.00
06/03/2022 02	65.14	57.580	$7.980	119.664	76.959	24.810	24.288	35.510	37.108	119.664	0.00	0.00

4

Title 807 | Chapter 005 | Regulation 056

807 KAR 5:056. Fuel adjustment clause.

RELATES TO: KRS 61.870 - 61.884, 143.020, Chapter 278
STATUTORY AUTHORITY: KRS 278.030(1), (2), 278.040(3)
NECESSITY, FUNCTION, AND CONFORMITY: KRS 278.040(3) authorizes the Public Service Commission to promulgate administrative regulations to implement the provisions of KRS Chapter 278. KRS 278.030(1) authorizes utilities to demand, collect, and receive fair, just, and reasonable rates. KRS 278.030(2) requires every utility to furnish adequate, efficient, and reasonable service. This administrative regulation establishes the requirements with respect to the implementation of automatic fuel adjustment clauses by which electric utilities may immediately recover increases in fuel costs subjected to later scrutiny by the Public Service Commission.

Section 1. Fuel Adjustment Clause. Fuel adjustment clauses that are not in conformity with the requirements established in subsections (1) through (6) of this section are not in the public interest and may result in suspension of those parts of the rate schedules based on severity of the nonconformity and any history of nonconformity.

(1) The fuel adjustment clause shall provide for periodic adjustment per Kilowatt Hour (KWH) of sales equal to the difference between the fuel costs per KWH sale in the base period and in the current period according to the following formula:

$$Adjustment\ Factor = \frac{F(m)}{S(m)} - \frac{F(b)}{S(b)}$$

Where F(b) is the cost of fuel in the base period, F(m) is the cost of fuel in the current period, S(b) is sales in the base period, and S(m) is sales in the current period, all as established in subsections (2) through (6) of this section.

(2) F(b)/S(b) shall be determined so that on the effective date of the commission's approval of t utility's application of the formula, the resultant adjustment shall be equal to zero.

(3) Fuel costs (F) shall be the most recent actual monthly cost, based on weighted average inventory costing, of:

(a) Fossil fuel consumed in the utility's own plants, and the utility's share of fossil and nuclear fuel consumed in jointly owned or leased plants, plus the cost of fuel that would have been used in plants suffering forced generation or transmission outages, but less the cost of fuel related to substitute generation; plus

(b) The actual identifiable fossil and nuclear fuel costs associated with energy purchased for reasons other than as established in paragraph (c) of this subsection, but excluding the cost o

KIUC HEARING
EXHIBIT 5

fuel related to purchases to substitute for the forced outages; plus

(c) The net energy cost of energy purchases, exclusive of capacity or demand charges irrespective of the designation assigned to the transaction, if the energy is purchased on an economic dispatch basis. Costs, such as the charges for economy energy purchases, the charges as a result of scheduled outage, and other charges for energy being purchased by the buyer to substitute for the buyer's own higher cost energy, may be included; and less

(d) The cost of fossil fuel recovered through intersystem sales, including the fuel costs related to economy energy sales and other energy sold on an economic dispatch basis.

(4) Forced outages are all nonscheduled losses of generation or transmission that require substitute power for a continuous period in excess of six (6) hours. If forced outages are not the result of faulty equipment, faulty manufacture, faulty design, faulty installations, faulty operation, or faulty maintenance, but are Acts of God, riot, insurrection, or acts of the public enemy, then the utility may, upon proper showing, with the approval of the commission, include the fuel cost of substitute energy in the adjustment. In making the calculations of fuel cost (F) in subsection (3)(a) and (b) of this section, the forced outage costs to be subtracted shall be no less than the fuel cost related to the lost generation until approval is obtained.

(5) Sales (S) shall be all KWH's sold, excluding intersystem sales. Utility used energy shall not be excluded in the determination of sales (S). If, for any reason, billed system sales cannot be coordinated with fuel costs for the billing period, sales may be equated to:

(a) Generation; plus

(b) Purchases; plus

(c) Interchange-in; less

(d) Energy associated with pumped storage operations; less

(e) Intersystem sales referred to in subsection (3)(d) of this section; less

(f) Total system losses.

(6) The cost of fossil fuel shall only include the cost of the fuel itself and necessary charges for transportation of the fuel from the point of acquisition to the unloading point, as listed in Account 151 of FERC Uniform System of Accounts for Public Utilities and Licensees, less any cash or other discounts.

Section 2. Filing Requirements.

(1) If a utility initially proposes a fuel adjustment clause, the utility shall submit copies of each fossil fuel purchase contract not otherwise on file with the commission and all other agreements, options, amendments, modifications, and similar documents related to the procurement of fuel supply or purchased power.

(2) Any changes in the contracts or other documents filed pursuant to subsection (1) of this section, including price escalations, and any new agreements entered into after the initial submission, shall be submitted at the time they are entered into.

(3) If fuel is purchased from utility-owned or controlled sources, or the contract contains a price escalation clause, those facts shall be noted, and the utility shall explain and justify them in writing.

(4) The monthly fuel adjustment shall be filed with the commission no later than ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustment.

(5) Copies of all documents required to be filed with the commission under this administrative regulation shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 through 61.884.

Section 3. Review of Fuel Adjustment Clauses.

(1) Fuel charges that are unreasonable shall be disallowed and may result in the suspension of the fuel adjustment clause based on the severity of the utility's unreasonable fuel charges and any history of unreasonable fuel charges.

(2) The commission on its own motion may investigate any aspect of fuel purchasing activities covered by this administrative regulation.

(3)

(a) At six (6) month intervals, the commission shall conduct a formal review and may conduct public hearings on a utility's past fuel adjustments.

(b) The commission shall order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments the commission finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices.

(4)

(a) Every two (2) years following the initial effective date of each utility's fuel clause, the commission shall conduct a formal review and evaluate past operations of the clause, disallow improper expenses and, to the extent appropriate, reestablish the fuel clause charge in accordance with Section 1(2) of this administrative regulation.

(b) The commission may conduct a public hearing if the commission finds that a hearing is necessary for the protection of a substantial interest or is in the public interest.

HISTORY: (8 Ky.R. 822; eff. 4-7-1982; Crt eff. 3-27-2019; 45 Ky.R. 3272; 46 Ky.R. 41, 435; eff. 8-20-2019; 47 Ky.R.1485, 1965; eff. 6-3-2021.)

PUBLIC SERVICE COMMISSION
OF WEST VIRGINIA
CHARLESTON

At a session of the PUBLIC SERVICE COMMISSION OF WEST VIRGINIA in the City of Charleston on the 9th day of January 2024.

CASE NO. 23-0377-E-ENEC

APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect.

and

CASE NO. 22-0393-E-ENEC

APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect.

and

CASE NO. 21-0339-E-ENEC

APPALACHIAN POWER COMPANY AND
WHEELING POWER COMPANY
Petition to Initiate the Annual Review and to Update the ENEC Rates Currently in Effect.

COMMISSION ORDER

The Commission rules on the reasonableness of Appalachian Power Company's (APCo) and Wheeling Power Company's (WPCo or Wheeling) (collectively the Companies) net Expanded Net Energy Cost (ENEC) costs and under-recoveries. The Commission disallows $231.8 million of requested ENEC under-recoveries. The remaining balance of the requested under-recoveries, which is currently $321.1 million, will not be allowed in rates until September 1, 2024, at which time it will be recoverable over a ten-year period at a rate of approximately $32.1 million per year plus a carrying cost allowance of four percent per year.

PSC STAFF HEARING
EXHIBIT 1

BACKGROUND[1]

On April 28, 2023, the Companies filed their 2023 petition to initiate the annual review and update of ENEC rates. The Companies submitted pre-filed direct and rebuttal testimony of nine witnesses providing details of the proposed ENEC rates.

The Companies sought to recover deferred and projected ENEC costs of $641.7 million, which is comprised of an accumulated under-recovery balance of $552,875,658, rounded to $552.9 million[2], as of February 28, 2023, and increased projected costs of $88.8 million for the forecast period of September 1, 2023, through August 31, 2024[3]. Under-recoveries are calculated by the Companies by comparing the actual net ENEC costs incurred on a month-by-month basis and the actual recoveries of ENEC costs at rates then in effect. If net costs in a month are greater than the ENEC revenues billed to customers, the Companies book an under-recovery. If net costs in a month are less than the ENEC revenues billed to customers, the Companies book an over-recovery. Both over- and under-recoveries are deferred and accumulated balances (net over-recoveries or under-recoveries) are considered by the Commission for deduction or addition to projected future ENEC revenue requirements for the purpose of setting prospective ENEC rates.

In this filing, the accumulated $552.9 million under-recovery balance reflects accumulated monthly net under-recoveries from March 1, 2021, through February 28, 2023. Normally, the Commission reviews over- or under-recovery balances and builds them into rates annually so that a fixed accumulated balance is amortized (built into rates) over one or more future ENEC rate periods rather than being carried forward from year to year without a recovery increment in rates. Beginning with Case No. 21-0339-E-ENEC (2021 ENEC), however, issues arose relating to whether the Companies were maximizing generation from their own plants in lieu of serving load with more expensive energy from the PJM Interconnection, LLC (PJM).[4]

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[1] For a complete procedural history, please see the case information for Case Nos. 21-0339-E-ENEC, 22-0393-E-ENEC, and 23-0377-E-ENEC at www.psc.state.wv.us.

[2] We will round the net ENEC numbers to the nearest $100,000 throughout this Order.

[3] On September 13, 2023, the Commission granted the Companies an increase in ENEC rates for the forecasted $88.8 million increased costs.

[4] PJM operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to transmission and performs long-term planning. In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of

It is important to note that throughout ENEC proceedings there are references to sales to and purchases from PJM. For a load-serving utility that has no other sources of power supply, a reference to power from PJM would be clearly understood to mean a purchase of power to serve load. However, for vertically integrated load serving utilities with their own power supply, the term "sale" refers to self-generated power that is delivered from the power plants into the transmission system and is accounted-for as a "sale" into PJM. The term "purchase" refers to the load of the utility which is taken from the transmission system and is accounted-for as a "purchase." In effect, the total net transaction of a load serving vertically integrated utility, which APCo and Wheeling are, is self-generation to serve load with an accounting performed by PJM. For example, If the load is 10 million Megawatt Hour (MWh) and the self-generation is 10 million MWh during a period when the PJM locational marginal price (LMP) is $40 per MWh, although the accounting may be referred to as a $400 million sale to PJM and a $400 million purchase from PJM, the net purchase from PJM would be zero and the only ENEC cost remaining to be paid by load would be the cost of the self-generation. That mechanism was explained in testimony from Mr. Vaughn, for the Companies:

> A. Yes. So regardless of your resources, you're purchasing all your load out of the RTO every hour of the year, right. You submitted an estimated load, which is your day ahead load, and then you have actual operating day. Results always vary. Any differences are made up in the real time or balancing market.
>
> And so the same thing is true then with your generation resources. You submit all [of] them day ahead and then the same results vary. You settle it up. And the bottom line is if those two things actually match one another in some weird instance, right, the net cost to customers is the fuel cost then to produce, --- to run those resources.
>
> Q. Right. And the price paid is the LMP, short term energy price.
>
> A. [Yes.] LMP, you would have purchased --- you know, simple world, no congestion, no losses, you would have purchased the

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thirteen states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia. PJM's markets include energy (day-ahead and real-time), capacity and ancillary services. PJM was founded in 1927 as a power pool of three utilities serving customers in Pennsylvania and New Jersey. In 1956, with the addition of two Maryland utilities, it became the Pennsylvania-New Jersey-Maryland Interconnection, or PJM. PJM became a fully functioning Independent Systems Operator in 1996 and, in 1997, it introduced markets with bid-based pricing and locational marginal price (LMP). PJM was designated a Regional Transmission Operator in 2001. https://www.ferc.gov/industries-data/electric/electric-power-markets/pjm.

[load] at an LMP and you would have sold at an LMP and those --- your market activity, wholesale activity nets to zero.

And in theory you have fuel and purchase power cost left.

Q. So if I bid in my coal plants and those coal plants clear the price, I'm essentially paying myself for that generation. And my cost is what it costs to run the plant, essentially?

A. Yes, in that scenario where --- you know, where they match up, correct.

Q. And if they don't match up, then I'm paying somebody else for that generation?

A. You're either paying PJM a net purchase power bill in that hour or you're receiving system sales revenues that go through to customers to reduce the ENEC costs.

2021 ENEC, March 23, 2022 Hearing Transcript (Tr.) at 228-29.

We will refer to PJM transactions in various ways throughout this Order, depending on the context, but it is important to keep in mind that gross deliveries by a utility into PJM and gross receipts of a utility from PJM may be referred to at times as sales and purchases, but those transactions must be considered as a net value to determine if there are any remaining MWhs to be considered a sale, or purchase. Otherwise, for self-generation that equals load, as Mr. Vaughn explained, the companies are receiving their own power back to serve load and "wholesale activity nets to zero." In that case, the PJM transaction portions of the ENEC would likewise net to zero and the ENEC cost would be, essentially "what it costs to run the plant."

Returning to the 2021 ENEC, the Commission allowed the under-recovery balance as of February 2021 to be recovered through rates over one year with the annual recovery increments being included in rates in the 2021 ENEC. The Commission indicated, however, that it might adjust or disallow continuing under-recoveries for rate making purposes. At the time of our September 2, 2021 Order in the 2021 ENEC, we established rates to go into effect for recovery of projected costs that should have been sufficient if future net PJM costs and Company generation costs, or the relationships between those costs, were reasonably close to the projections made by the Companies, and if the Companies relied more on self-generation for their power supply.

The history and record of the current case (2023 ENEC) are heavily intertwined with the previous two ENEC proceedings of the Companies: the 2021 ENEC referenced above and Case No. 22-0393-E-ENEC (2022 ENEC). The final and substantive procedural orders issued in those cases document the record and Commission decisions leading to the Orders in this proceeding.

After a reopening of the 2021 ENEC Case in the spring of 2022, we learned that under-recoveries were growing because the net cost of PJM transactions was escalating, and the Companies were relying even more on expensive non-self-generated power supply than they had originally projected. 2021 ENEC, Mar. 23, 2022 Tr. at 29-33. It was also becoming even more apparent that, as the Commission had concluded in its September 2, 2021 Order in the 2021 ENEC, the LMP for PJM power was becoming even more expensive than the cost of self-generation. By the spring of 2022, the Companies were no longer claiming that self-generation was more expensive than PJM power. Instead, they blamed their increased reliance on PJM power on an inability to obtain sufficient coal supplies to maximize economical self-generation. 2022 ENEC, Petition, Apr. 19, 2022 at Exh. JCD-D generally; 2023 ENEC, Cos. Initial Br. at 6.

The Commission ordered Commission Staff to "conduct a review . . . of the Companies' generation plant availability and utilization and ENEC costs." 2021 ENEC, Comm'n Order, May 13, 2022. The Staff review had not been completed and filed when the Commission entered its final order on February 3, 2023, in the 2022 ENEC. In that order, the Commission denied an ENEC increase until Staff completed the review ordered in the 2021 ENEC. After issuance of the Staff-contracted report on the reasonableness of the Companies' net ENEC costs and the prudency of their decisions and actions relating to self-generation and net purchasing and selling power through PJM (Prudence Review), the Commission reopened the 2021 ENEC and 2022 ENEC by order entered May 26, 2023. The Commission scheduled an evidentiary hearing on the Prudence Review to begin immediately prior to the evidentiary hearing in the 2023 ENEC case.

In the 2023 ENEC, the Companies were represented by William C. Porth, Esq. and Anne C. Blankenship, Esq., and Jonathan C. Stanley, Esq. of Robinson & McElwee PLLC.; James R. Bacha, Esq. of American Electric Power Service Corporation; and Keith D. Fisher, Esq., of Appalachian Power Company. Intervenor Kanawha County Commission (KCC) was represented by Marc J. Slotnik, Esq. and Christopher M. Settles, Esq. Intervenor West Virginia Energy Users Group (WVEUG) was represented by Derrick P. Williamson, Esq., Barry A. Naum, Esq., Steven W. Lee, Esq., and Susan J. Riggs, Esq. of Spilman, Thomas & Battle, PLLC. Intervenor West Virginia Coal Association (WVCA) was represented by H. Brann Altmeyer, Esq. and Jacob C. Altmeyer, Esq. of Phillips, Gardill, Kaiser & Altmeyer, PLLC. Intervenor Consumer Advocate Division (CAD) was represented by Robert F. Williams, Esq., Heather B. Osborn, Esq., and John Auville, Esq. Staff was represented by Lucas Head, Esq.

In the 2021 ENEC, the Companies, WVEUG, CAD, and Staff were represented by the above-named individuals and firms. Intervenor Steel of West Virginia, Inc. (SWVA) was represented by Charles K. Gould, Esq. of Jenkins Fenstermaker PLLC. In the 2022 ENEC, the Companies, WVEUG, WVCA, SWVA, CAD, and Staff were represented by counsel set forth above.

DISCUSSION

I. Prudency and Disallowance of Unreasonable, Imprudently Incurred ENEC Costs.

The actions taken by the Companies leading to the amount of power generated at their three coal-fired generation plants occurred during months encompassed by the 2021, 2022, and 2023 ENEC cases. The 2023 ENEC case included a request for a $552.9 million under-recovery revenue requirement for the period from March 1, 2021, through February 28, 2023, to be paid by customers in the rates to be set in the 2023 ENEC case. The actions of the Companies to minimize their ENEC costs is the initial issue confronting the Commission.

It is necessary to consider the entire record of the 2021, 2022, and 2023 ENEC cases to determine if the Companies prudently, efficiently, and reasonably used economic self-generation from their own power plants in lieu of higher cost net PJM power. In order to determine if excessive costs were incurred because of the Companies' decisions and actions that left them with insufficient supplies of coal for economical self-generation, it is also critical for the Commission to consider whether the Companies used the minimum amount of high-priced PJM energy market electricity over the period of review or whether the net power supplied through PJM transactions in lieu of self-generation was excessive.

We have determined that having insufficient supplies of coal in inventory and scheduled for delivery into the Companies' plants led to the lowest level of generation in the last twenty years[5] during a period when the PJM LMP spiked to the highest levels experienced in the last twenty years.[6] This "perfect storm" led to an inability to maximize economic generation while using excessive amounts of PJM power. The burden of a significant portion of the resulting excessive costs

[5] EIA Power Plant data. See Table 2, infra.

[6] PJM 2022 State of the Market Report, See Table 1, infra.

must fall on the Companies because their fuel supply failures and related market offer strategies that lead to rejection of their power plants for dispatch by PJM directly caused the excessive ENEC costs.[7]

The parties put forward a number of recommendations regarding prudency and disallowance of the under-recovery for ratemaking purposes. The Companies, obviously, recommended and requested full recovery of the $552.9 million.[8] To moderate the impact on customers, the Companies proposed two alternative recovery mechanisms. One mechanism is to amortize the deferred under-recovery over three years with a carrying charge at the Companies' weighted cost of capital. The alternative mechanism is to securitize the deferred under-recoveries along with additional securitization of unrecovered investments in certain power plants and certain other deferred costs.

The CAD, at the other end of the spectrum, recommended that the Commission disallow the entire under-recovery. Alternatively, to the extent the Commission allows any portion of the $552.9 accumulated under-recovery in rates, the CAD recommended that the amount allowed be amortized over no less than five years with no carrying charge.

The WVEUG recommended a disallowance of $82.6 million before any consideration of amortization or securitization. WVEUG further recommended that any balance recoverable in rates be allowed a carrying charge of four percent. However, instead of amortization, WVEUG preferred securitization with certain other conditions attached. Those conditions were: (1) a freeze on the ENEC filings for at least one year; (2) a freeze on filing a full Base Rate case until April 2025; and (3) a minimum $82.6 million disallowance. Given those conditions, WVEUG preferred the securitization proposal.

Staff, through the testimony and evidence of Critical Technologies Consulting (CTC), recommended that the Commission find imprudence on the part of the Companies and disallow $257,993,417 of the under-recovery. 2023 ENEC, Tr. Sept. 7, 2023 at 408.

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[7] Q. If the Companies could have, based on the market conditions that we've talked about, the outages at the time and then also the lack of coal, if they could have hit the 69-percent capacity factor, would they have?
A. Yes. There's nothing --- in a hypothetical world where we had an abundant or unlimited amount of coal last fall [fall of 2021] and the units weren't in outage, we would have [run] them nonstop in these power prices. 2021 ENEC, Testimony of Mr. Vaughn, Mar. 23, 2022 Tr. at 246-47.

[8] On December 27, 2023, the Companies, WVEUG, and WVCA recommended reducing this amount by $50 million if the Companies could finance the remaining amount through securitization. 2023 ENEC; Stipulation filed Dec. 27, 2023. Staff, KCC, and CAD opposed the Stipulation. Staff letter filed Dec. 28, 2023; KCC filing, Jan. 2, 2024; CAD filing Jan. 5, 2024.

Staff engaged CTC to conduct the Prudence Review. The focus of the review was the Companies' policies and procedures for maximizing and maintaining adequate fuel inventory levels, and bidding their plants into the PJM market to maximize economical self-generation, recognizing that it may be necessary to deliver into the PJM Market at a small loss in some hours to capture the net benefits of higher market prices within any twenty-four-hour period. 2021 ENEC, Comm'n Order, May 13, 2022, at 6. The Prudency Report prepared by CTC (Prudency Report) determined that the Companies' plants were dispatched by PJM at an aggregate 32.5 percent per year. 2021 ENEC, Prudency Report filed April 28, 2023 at 39 (Bates No. 42). CTC found that the Companies' coal plants are in good condition and capable of dispatch. CTC found, however, that over the ten-year period prior to the report being filed with the Commission, the Companies placed an overreliance on net power supply from the PJM market and significantly reduced self-generation. Prudency Report at 10; Staff Initial Br. at 4-5. Further, the Companies did not appear to take seriously the Commission decision in the 2021 ENEC and 2022 ENEC that directed the Companies to self-generate more of their required power.

As discussed in the Prudency Report and testimony, the Companies built up larger than normal coal stockpiles through 2020. However, by May 2021, the Companies should have been concerned by the diminishing stockpiles of coal in inventory. The Companies should have realized in May 2021, but no later than July 2021, that the coal shortages at their plants would prevent them from self-generating at a meaningful level to offset rising PJM Energy market prices. In July 2021, the stockpiles were critically short, yet no action was taken until September 20, 2021, when the Companies issued a coal supply Request for Purchase (RFP)[9]. By this point, it was already too late to replenish the stockpiles. Only one coal supplier responded in the affirmative to the RFP and even that offer was rescinded. 2022 ENEC, Oct. 4, 2022 Tr. at 279.

CTC expressed concern that the Companies did not appear to take seriously the Commission directive to increase the plant capacity factors to 69 percent. The Companies argued for several months that the September 2021 Commission Order was not clear, and the Commission has since failed to clarify it despite numerous requests to do so.[10] 2022 ENEC, Petition, Apr. 19, 2022 at Exh. JCD-D pp. 14-15.

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[9] Ms. Chilcote testified for the Companies that they realized the shortfall in late August 2021. Sept. 6, 2023 Tr. at 137.

[10] The Commission has explained several times that we arrived at the 69% capacity factor as a minimum target to strive for, based on the evidence before us in the 2021 ENEC that self-generation was more

CTC did not find any evidence that the Companies made changes in the fuel procurement process or bidding their energy into PJM to allow them to provide more self-generation and increase the capacity factor of their plants. The Companies failed to tell a key employee, Mr. Dial, who was in charge of fuel procurement, of the 69 percent capacity factor target set forth in the September 2, 2021 Commission Order. 2021 ENEC, Mar. 23, 2022 Tr. at 173, 211; 2022 ENEC, Oct. 4, 2022 Tr. at 280. Eighteen days later, Mr. Dial issued an RFP for more coal, unaware, pursuant to his testimony, of a need to not only replenish the stockpiles, but also to be able to meet the 69 percent average generating rate target that had been established by the Commission. 2021 ENEC, Mar. 23, 2022 Tr. at 173-74. The Companies presented conflicting testimony on this issue with Mr. Scalzo testifying during the 2021 ENEC hearing on the Petition to Reconsider that the September 2021 RFP was a direct reaction to the Commission's September 2021 order. 2021 ENEC, Mar. 23, 2022 Tr. at 90, lines 1-9.

Even after the March 2, 2022 Commission Order on the Petition for Reconsideration, the Companies did not tell Mr. Dial to procure sufficient coal that would allow the Companies to achieve the 69 percent capacity factor target if PJM energy prices continued to increase above earlier projected prices and far above the low levels of PJM market prices in 2020. 2021 ENEC; Mar. 23, 2022 Tr. at 211. The Companies appear to be short of contracted coal supply to self-generate at a maximum capacity factor, or at a minimum 69 percent capacity factor, even if it is economical to self-generate and save money for ratepayers, as shown in Companies' Post-Hearing Exhibit 2 filed on September 15, 2023. That exhibit shows that the Companies required more coal to generate at a 69 percent annual capacity factor at each of their plants than they had under contract.[11]

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economical than relying on non-self-generated power. There should be no misunderstanding about maximizing self-generation and striving for a minimum target capacity utilization level when self-generation was the most economical power supply choice. If the projections regarding the economic benefit of self-generation had been incorrect, the Companies could have planned their daily generation accordingly and explained why that resulted in not meeting the target capacity utilization level. As it turned out, there was no question that self-generation would have been economic for most of the period March, 2021 through February 28, 2023 if the Companies had adequate coal supplies. Not understanding the intent of our capacity utilization target is no excuse for failing to maintain adequate coal stockpile levels to maximize generation when the economic benefits of self-generation turned out to be even greater than had been anticipated in the 2021 ENEC. The issue in this case is not whether the Companies achieved a 69 percent capacity factor, or any specific capacity factor, it is that they did not maintain adequate coal stockpiles and incoming coal supplies to maximize generation when it was prudent to do so.

[11] The exhibit shows that Amos requires 9,982,020 tons per year to operate at full load, and 6,887,594 tons to operate at a 69 percent capacity factor. It also shows 6,483,855 tons of coal under contract. It is not clear whether the contract amount is per year, or over multiple years. Even if the amount shown represents annual tons under contract it represents only 65 percent of what is needed to run at full load and only 94 percent of what is needed to run at a 69 percent capacity factor. For Mountaineer, the volume

II. Commission Findings.

The Companies have the burden of proving that their ENEC costs were reasonable and the result of prudent management of their generation assets, fuel supplies, and net power supply from PJM in lieu of self-generation. 2021 ENEC, Comm'n Order, May 13, 2022, at 6. While any contemporary action must be based on what is known or reasonably knowable at the time the action is taken, a continuum of actions leading up to a decision point must also be taken into consideration when determining prudency. The contemporary actions and abilities regarding self-generation in any single month from March 2021 through February 2023 are part of a continuum of practices and actions which we determine were unreasonable and not prudently designed to protect customers against excessive net ENEC costs. We have been told by the Companies that their coal-fired plants are valuable assets that provide a physical hedge against high and volatile PJM energy prices.[12] We have agreed that coal-fired power plants are valuable assets and have ruled favorably on acquisition and upgrades of power plants. It is not our job, however, to manage and operate the plants so that they will provide the expected hedge against volatile energy costs when needed. To take advantage of the hedge benefit, it is the responsibility of the Companies to assure that they can operate the plants when the volatile energy markets they warned of expose them to high ENEC costs.

During the period of the under-recovery under consideration in these proceedings, the Companies did not prudently maintain adequate fuel supplies and manage operations of their coal-fired power plants to provide the physical energy hedge that they have described as a protection against volatile energy costs. As described in the Prudency Report, the Companies did not react prudently to the warning signals they were receiving. There was a clear decline in coal stockpiles from the end of 2020 to mid-2021. This drop may have been a concern, but not alarming, except for the fact that the PJM market prices, using Amos Day Ahead PJM LMP as a yardstick, had climbed from near \$20.00 per MWh in 2020 to \$23.81 per MWh in March 2021 (a 19 percent cost increase), then to \$34.87 per MWh in July 2021 (an additional 46 percent cost increase), and were on an upward trajectory that would eventually peak at \$91.88 per MWh in August 2022 (an additional 163 percent cost increase).

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under contract also is only 65 percent of what is needed to run at full load and 94 percent of what is needed to run at a 69 percent capacity factor. For Mitchell, the volume of coal under contract is only 43 percent of what is needed to run at full load and only 63 percent of what is needed to run at a 69 percent capacity factor.

[12] "Amos and Mountaineer also serve as a physical hedge, and without them, our customers would be increasingly exposed to potentially volatile energy costs." Case No. 20-1040-E-CN; Tr. of June 8, 2021, at Cos. Exh. CTB-D, p. 6, lines 4-5.

By May 2021, the Companies should have been concerned by the diminishing stockpiles of coal in inventory. They apparently were not concerned as stockpiles continued to decline. By July 2021, the coal stockpiles were critically short, yet no action was taken until September 20, 2021, when the Companies issued an RFP for coal. By then the average PJM Day Ahead LMP at Amos had already doubled from the 2020 levels to $43 per MWh and self-generation was clearly prudent and necessary to minimize quantities of net purchased power. It is unfathomable that the Companies; with (1) a long history of reliance and expertise in coal-fired generation, (2) prior requests for ratepayer support of base-load coal-fired generation, which were generally granted by the Commission; and (3) purported commitment to upgrade, maintain and preserve these valuable generation assets for many years, could not operate the plants when needed to offset non-self-generated power because of a lack of adequate coal stockpiles and incoming coal supplies to replenish stockpiles as they were used.

Declining coal stockpiles, lack of attention to timely contracting for incoming coal to replenish stockpiles and a rapidly rising PJM LMP are a recipe for a catastrophic level of ENEC costs. The Companies claim that they did nothing wrong and that their actions were reasonable and prudent. We disagree. Instead, we find that their lack of action was unreasonable and imprudent. ENEC under-recoveries were climbing dramatically due to over-reliance on third-party power supplies at rising cost levels that could have been offset by self-generation if the Companies had acted reasonably and prudently in a timely manner.

As a result of their unreasonable and imprudent management, the Companies incurred excessive net ENEC costs that should not be shouldered entirely by customers. The Commission has long supported self-generation not only as a hedge against over-reliance on volatile outside power but also because of the reliability of properly managed, fuel-secure, steam-powered generating plants. It is unconscionable that the Companies would allow their inventories of coal to drop to such low levels that they were unable to generate electricity in any semblance of reasonable quantities to offset incoming PJM energy at costs that were not just marginally higher, but were much higher, than self-generation.

Furthermore, the Companies demonstrated an imprudent lack of ongoing attention to assure that they had a continuous supply of coal to maintain adequate stockpiles of coal to maximize generation when it was cheaper than PJM energy prices. It was the Companies' responsibility to structure their coal supply contracts in a manner that would allow them to respond to rising PJM LMPs by increasing the utilization of their power plants without running out of coal. This may take a mix of long-term, medium-term, and short-term contracts and spot purchases when necessary.

It is not our responsibility to manage the day-to-day operations of the Companies or dictate the mix of coal contracts. That responsibility lies squarely on the management of the Companies. As utilities have often reminded us, the Supreme Court of Appeals of West Virginia has held that the Commission is not a super board of directors. However, at the same time, the Court has held that when the utility management acts in an unreasonable and imprudent manner, the Commission has the authority to protect customers from the negative financial consequences of the utility unreasonable actions, or inactions.[13] [14]

The Companies are required by law to: "maintain a minimum 30-day aggregate coal supply under contract for the remainder of the life of those [coal-fired generation] plants." W. Va. Code § 24-2-1q. They claim to have met that statutory requirement, although the data submitted in Companies' Post-Hearing Exhibit 2 filed on September 15, 2023 (discussed above), calls that into question since a shortfall in annual coal quantities under contract necessary to generate at full load may also signal a shortfall in quantities to meet a minimum 30-day supply unless the annual amounts are deliverable monthly at a greater than pro-rata level. Reasonable and prudent management must assure not only that contracts are in place to cover a minimum 30-day aggregate coal supply for the remainder of the life of the generating plants, but also assure that the incoming coal supplies replace coal as it is used so that the plants could actually operate to offset purchased power quantities (and bring the net of receipts from PJM minus deliveries to PJM close to zero, or below) without running inventories down to dangerously low levels. If the Companies had managed their stockpile levels reasonably and prudently, they would not have experienced the unreasonably low inventory levels that they now use to excuse their inability to maximize the use of the plants when PJM hourly day-ahead LMP reached levels that resulted in net ENEC costs of hundreds of millions of dollars that the Companies now expect customers to pay.

The Commission finds that the Companies failed to obtain adequate fuel supplies and manage power plant operations in a reasonable, prudent, and efficient manner. As a result, during the period under review in these proceedings

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[13] While the PSC is not to be seen as a super board of directors for the public utility companies of the State, at the same time "[t]heir function is to regulate and disapprove any dishonest or clearly inefficient conduct and practice by the utility. Lumberport-Shinnston Gas Co. v. Public Serv. Comm'n 271 S.E.2d 438 (1980),(citing United Fuel Gas Co. v. Public Serv. Comm'n, 154 W.Va. 221, 243, 174 S.E.2d 304, 317 (1969), (citing, Southern Bell Telephone and Telegraph Company v. Georgia Public Serv. Comm'n, 203 Ga. 832, 848, 49 S.E.2d 38, 66 (1948)).

[14] The Public Service Commission is not a super board of directors. Its sole power is to see that in the matter of rates, service and facilities, their treatment of the public is fair. United Fuel Gas Co. v. Public Serv. Comm'n, 154 W.Va. 221, 243, 174 S.E.2d 304, 317 (1969), (citing Northern Pennsylvania Power Co. v. Pennsylvania P.U.C.)

Table 1

	Day-Ahead Load-Weighted Average LMP			Year to Year Change			
	Average	Median	Standard Deviation	Average	Average Percent	Median	Standard Deviation
2001	$36.01	$29.02	$17.48	NA	NA	NA	NA
2002	$31.80	$26.00	$20.68	($4.21)	(11.7%)	(10.4%)	(44.8%)
2003	$41.43	$38.29	$21.32	$9.63	30.3%	47.3%	3.1%
2004	$42.87	$41.96	$16.32	$1.44	3.5%	9.6%	(23.4%)
2005	$62.50	$54.74	$31.72	$19.62	45.8%	30.4%	94.4%
2006	$51.33	$46.77	$26.45	($11.16)	(17.9%)	(14.6%)	(16.6%)
2007	$57.88	$55.91	$25.02	$6.55	12.8%	19.7%	(5.4%)
2008	$70.25	$62.91	$33.14	$12.37	21.4%	12.5%	32.4%
2009	$38.82	$36.67	$14.03	($31.43)	(44.7%)	(41.7%)	(57.7%)
2010	$47.65	$42.06	$20.59	$8.83	22.7%	14.7%	46.8%
2011	$45.19	$39.66	$24.05	($2.46)	(5.2%)	(5.7%)	16.8%
2012	$34.55	$31.84	$15.48	($10.64)	(23.5%)	(19.7%)	(35.6%)
2013	$38.93	$35.77	$18.05	$4.37	12.7%	12.3%	16.6%
2014	$53.62	$39.84	$59.62	$14.70	37.8%	11.4%	230.4%
2015	$36.73	$30.60	$25.46	($16.89)	(31.5%)	(23.2%)	(57.3%)
2016	$29.68	$27.00	$11.64	($7.05)	(19.2%)	(11.8%)	(54.3%)
2017	$30.85	$28.21	$12.64	$1.17	3.9%	4.5%	8.6%
2018	$37.92	$32.49	$24.76	$7.11	23.1%	15.2%	95.9%
2019	$27.23	$25.28	$10.18	($10.74)	(28.3%)	(22.2%)	(58.9%)
2020	$21.40	$19.78	$7.59	($5.83)	(21.4%)	(21.7%)	(25.5%)
2021	$39.37	$33.72	$19.30	$17.97	84.0%	70.5%	154.1%
2022	$75.44	$64.13	$41.25	$36.07	91.6%	90.2%	113.8%

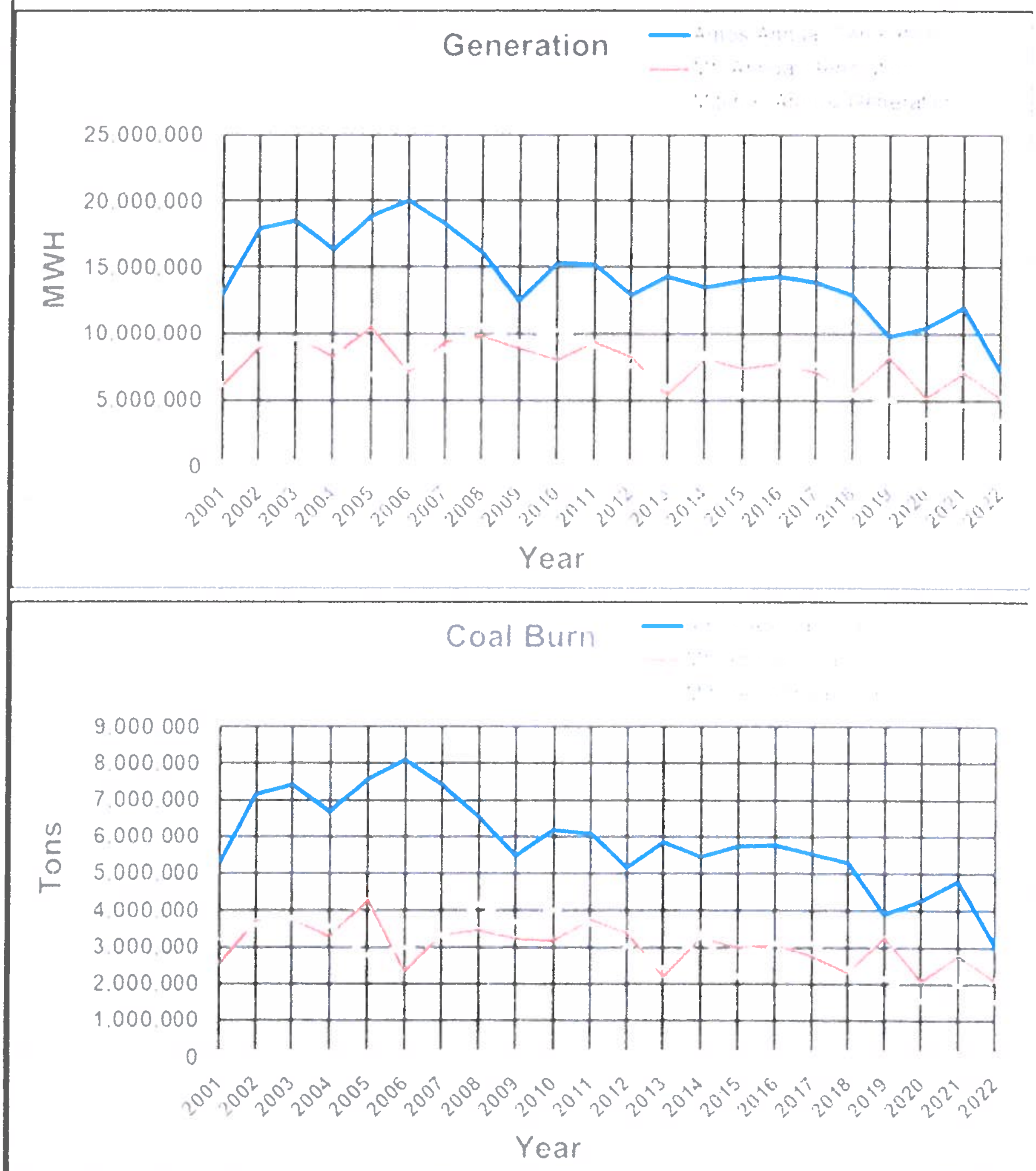
The nominal yearly PJM day-ahead load-weighted average LMP for 2022 was the highest since the first full year of the PJM day-ahead energy market in 2001. 2022 State of the Market Report for PJM, Section 3, Energy Markets https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/20

they received excess amounts of power from the PJM market, that were not offset by self-generation, at prices that, as shown in the above Table (Table 1) and report of the PJM Independent Market Monitor, were at the highest level in PJM History. The Day-Ahead system-wide LMP nearly doubled in 2021, going from an average of $21.20 per MWh in 2020 to $39.37 per MWh in 2021. Then, the price jumped to an average of $75.44 per MWh in 2022.

Unfortunately, rather than being in a position to offset incoming power from PJM at prices that far exceeded what it would cost the Companies to generate from their own plants, the Companies continued on a dangerous downward slope of underutilization of their plants, culminating in the worst level of utilization in twenty years, occurring precisely at the worst time as the PJM LMP reached, on average, over $75 per MWh and were at times in excess of $90 per MWh.

The following chart (Table 2) taken from the Energy Information Administration (EIA) Power Plant data shows that all three coal-fired power plants of the Companies are capable of generation far in excess of the abysmal usage level they achieved in 2021 and 2022, while the Companies were paying so much for net incoming PJM power in lieu of self-generation that their ENEC under-recovery didn't just balloon, it rocketed to the stratospheric level of $524.9 million.

Table 2



While the Companies paint a picture of declining PJM prices in 2019 and 2020 that made self-generation of limited benefit at best, that was a period of economic downturn, collapsing natural gas prices, and Covid shutdowns. Failure to realize that even a modest turnaround could significantly increase the market price of power led to failure to maintain coal inventories and adequate incoming supply to cover the inevitable increase in PJM market prices after the recovery from the economic downturn of 2019/2020. These failures left the Companies' customers dangerously and disastrously exposed to price escalations in 2021 and 2022. As PJM average LMP climbed from $21.40 per MWh in 2020 to $39.37 in 2021, the Companies' coal burn and related MWh generation at its power plants ticked upward only slightly. Table 2. Even worse, when the PJM LMP skyrocketed to an average of $75.44 in 2022, the Companies' coal burn and MWh output plummeted in the opposite direction. Id. The results were excessive net incoming PJM power to meet internal load and little, if any, sales of excess self-generated power not needed for internal load that could have generated net positive margins to offset ENEC costs.

We have previously recognized that low-cost self-generation benefits customers in two ways: First, because such low-cost generation could serve internal load in lieu of purchasing more expensive power to serve internal load; and second, net system sales into the wholesale market could generate margins that further reduce net ENEC costs. From the outset of what the Commission referred to as "Fuel-Review" proceedings in the late 1970s, and subsequent evolution into "Energy Cost" proceedings, "Net Energy Cost" (NEC) proceedings, and "Expanded Net Energy Cost" proceedings, we have cautioned electric utilities that they have the responsibility to minimize the net ENEC costs that are passed through to customers, particularly in expedited, non-base rate proceedings. Achieving net system sales (wholesale sales in excess of purchases that produce net positive margins) has always been a goal that we have stressed that the utilities must maximize.

The purchased power and capacity related components of our present ENEC proceedings are often referred to as system transactions or system sales. They involve day-to-day power sales and purchases both intra-system (American Electric Power or American Electric Power Service Corporation) and inter-system (neighboring non-affiliated utilities). These expanded cost components were incorporated into the ENEC with the Commission warning the utilities that automatic pass-through was not guaranteed and that the Companies had the burden to prove that they were maximizing the net margins from system transactions (revenue in excess of marginal costs) through aggressive management of their generation assets. The Commission explained the potential downside and the potential upside of expedited reviews of power supply costs when it first considered an "Expanded" NEC procedure in 1984.

> Generally, system sales is the term used to describe voluntary opportunity transactions with the member companies of the AEP System as sellers and other independent, unaffiliated interconnected utilities as buyers. . . .
>
> The stipulation [in Case No. 83-697-E-42T] points out that these opportunity sales are unpredictable with respect to volume and profitability since they are dependent on a variety of factors that are difficult to predict. . . . Recognizing the difficulty in predicting a sales realization that will closely reflect the actual system sales realized, Staff and Company agreed upon a concept for purposes of the stipulation. This concept, which is experimental in nature, will remove all system power costs and system sales revenue from rate cases and consider them in the Annual Net Energy Cost (NEC) review proceedings. Inclusion of these items in an "Expanded Net Energy Cost" concept and the application of deferred accounting treatment will greatly reduce the risk associated with predicting future system sales levels or costs associated with such sales. Moreover, customers will receive the benefits associated with these sales on a more timely basis. . . . (Stipulation, pp. 22-24).
>
> CAD opposes incorporating the test year level of system sales in rates as well as to the adoption of the expanded NEC, even on an experimental basis. . . . CAD argues that if no system sales occur under expanded NEC, ratepayers alone bear the risk of supporting excess capacity. . . .
>
> The stipulation adopts the expanded NEC concept on an experimental basis. System sales, as pointed out by the stipulation's discussion, are opportunity sales which are difficult to forecast as to volume or profit. . . . We will adopt the expanded NEC concept, but only on an experimental basis. Therefore, APCo is on notice that we may remove the expanded portion of the NEC in any future fuel review or general rate case and return that increment to base rates.

Appalachian Power Co., Case No. 83-697-E-42T, Comm'n Order, Sept. 28, 1984, at pp. 15-17.

For many years of the Fuel Review, NEC, and ENEC proceedings, the system transactions were bi-lateral in nature, involving day-to-day power plant operational decisions, including economic dispatch, energy sales and energy purchases, agreed to between our West Virginia electric utilities and neighboring utilities. Beginning around 2000, however, PJM, which the Federal Energy Regulatory Commission (FERC) encouraged to assume operational control over electricity transmission within a multiple state footprint, began operating bid-based energy markets. Transactions that had been ad hoc arrangements between neighboring utilities[15] became PJM market-based transactions. Initially, the PJM prices were high compared to the cost of generation by West Virginia or affiliated utility-owned, mostly coal-fired, steam generation facilities. As was the case when system transactions were a function of trading available lowest cost generation between neighboring utilities, the transactions into (sales) and out of (purchases) the PJM Market favored West Virginia utility and affiliate-owned power plants. As low-cost producers, it took little effort to plan to serve internal load from the lowest cost utility-owned power generation available and to sell any excess energy from the higher cost generation into the PJM Market at a positive net margin (incremental profit).

As can be seen in Table 1 above, PJM energy market prices were relatively high from 2001 until approximately 2018. Self-generation costs varied in those years, but typically were in the range of $15 per MWh to the mid $20 per MWh range.[16] Our expectations, both before and after the creation of the PJM energy markets, and our message to the utilities, has been not only to minimize the percentage of load served from purchased power, but also to sell their excess power to neighboring utilities or into the PJM market at net margins to be used as "credits to cost of service" to reduce the rates of West Virginia customers.

In 2019 the PJM market prices dropped and in 2020 they had collapsed to below $22 per MWh average for the year and temporarily dropped below West

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[15] These arrangements worked quite well, producing a shared benefit for both buyers and sellers.

[16] The following table shows costs of generation as reported by APCo in its Annual Reports to the Commission.

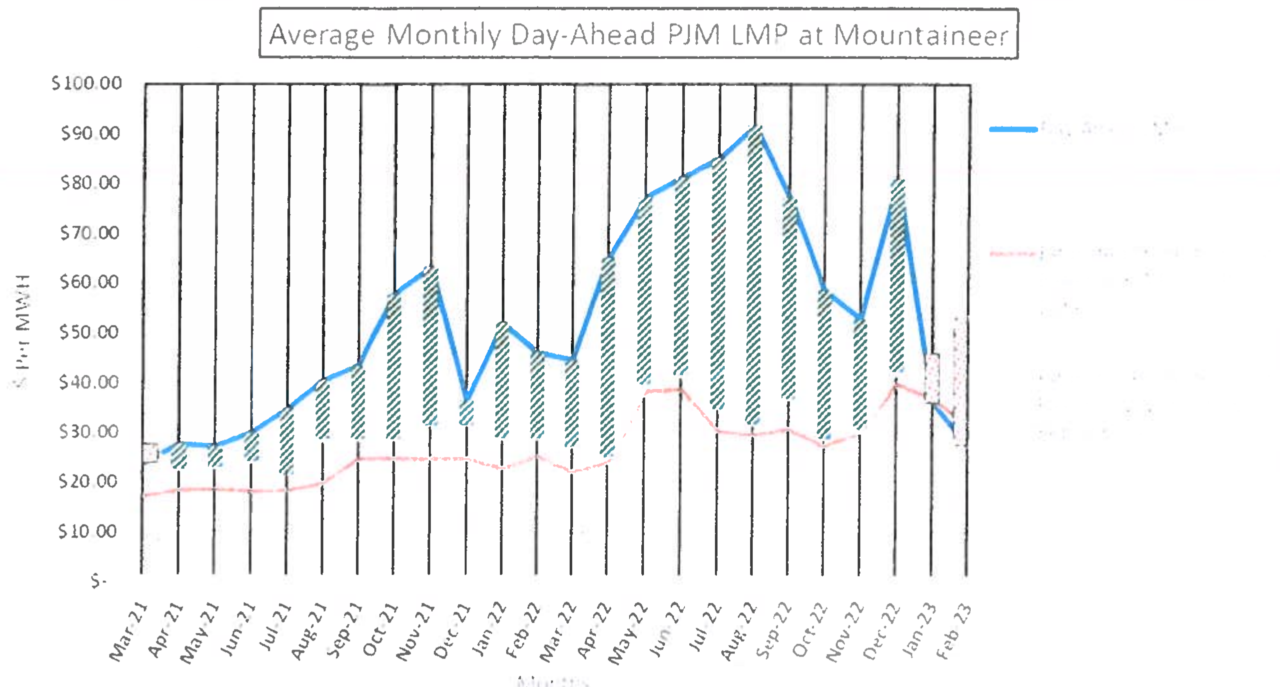
Fuel, Allowance and Steam Expenses Cost of Generation per Net MWh Data from Annual Reports Filed by APCo *		
Year	Amos	Mtr
2000	$13.32	$16.08
2005	$16.41	$16.81
2010	$24.51	$28.39
2015	$25.71	$25.08
2020	$25.65	$22.18
* Includes all Steam and Miscellaneous Steam Expenses reported. All of these costs may not be directly variable prorata to production. Therefore, these values likely overstate actual variable costs.		

Virginia generation costs. Therefore, the Companies understandably acquired, larger percentages of the power supply to serve West Virginia load at those low market prices. The cost of coal-fired generation, however, remained close to the cost of PJM energy. We never suggested to the Companies in any previous ENEC orders, or any orders, that they should forego having sufficient fuel inventories, having sufficient coal under contract, prudently bidding into the PJM market, and operating power plants to maximize their coal-fired generation and instead, become addicted to price-volatile PJM Energy Market electricity. Even when PJM energy prices are low on average, there are opportunities for the Companies to earn positive net margins during certain hours and peak periods and there are reliability benefits of having always-available, fuel-secure, thermal generating plants on line and prepared to balance load and generation. Thus, it was and is necessary that they manage their fuel and generation resources to remain prepared to take advantage of those opportunities and contribute to maintaining system reliability, even at relatively low PJM prices, and to be able to quickly respond with increased generation when PJM prices or load increased.

In the 2021 ENEC proceeding, the Commission noted that the Companies' own projections indicated an over-reliance on net market supplied power at cost levels that were already trending upward from the 2020 price levels. The Commission further stated that over-reliance on net purchased power indicated an imprudent under-reliance on the utilization of the Companies' power plants. 2021 ENEC, May 13, 2022 Comm'n Order at 4-5. The Commission warned the Companies that failure to maximize the output of their own power plants could result in disallowance of costs in future ENEC proceedings. Id. at Conclusion of Law 3.

In the first months of 2021, the difference between the cost of self-generation by the Companies and purchasing power was relatively small, but significant enough to warrant a close review of the Companies' projections of seemingly unreasonably high levels of net quantities of PJM power needed to serve their load. During, and immediately after, our analysis in the 2021 ENEC proceeding, our concerns were proven painfully correct as the difference between purchasing power and self-generation costs at the Companies' power plants escalated. The following Table (Table 3) shows the monthly changes in average day-ahead PJM energy market prices based on the PJM price at the Mountaineer power plant and compares the escalating PJM market prices to the cost of generation at Mountaineer. Similar relative trends occur at Amos and Mitchell.

Table 3



For this table we have calculated the variable cost of generation using the Coal Report data submitted to this Commission and the fuel data submitted by APCo to the EIA. These production cost calculations are based on the cost of monthly incoming coal rather than an inventory value. In a rising cost market, use of last-in costs in place of average inventory value costs will overstate the production costs to some degree. We do not expect that the Companies have or should change their average inventory cost accounting. We make the calculations based on incoming coal costs for Table 3 merely for purposes of simplification. The Coal Report data includes a breakdown of Free on Board (FOB) Mine costs, transportation costs, and handling costs. That level of detail may not be in the data reported to the EIA. This different reporting detail may account for the slight differences between the EIA and Coal Report data. To allow for consumables, we have added $4 per MWh to the calculated production costs for both the EIA and coal report data.

Table 3 data illustrates that the narrow differences between PJM market prices and the Companies' production costs widened dramatically from early 2021 to December 2022. The magnitude of the excess costs of PJM energy is represented by the differential, green-striped bars between the production cost curves and the PJM market price curve. The differential values go from a small negative in March 2021 to positive values beginning in April 2021. Those positive differentials were relatively small, but significant up to July 2021 before they ballooned to extreme levels, except for a narrower differential in December 2021 due to a dip in the PJM price in that month.

The Companies have argued that they faced rising coal costs beginning in 2021, so their generation costs also rose. Clearly, the coal costs and resulting calculated production costs increased starting in mid-2021, and the rate of increase became more significant from March 2022 to July 2022. The calculated production cost increase from approximately $20 per MWh in March 2021 to almost $40 per MWh would have caused increased ENEC costs. But the roughly $20 per MWH increase in production costs pales in comparison to the PJM market price which jumped from around $30 per MWh in the spring of 2021 to $60 per MWh by November 2021, and then after a brief pull-back climbed in 2022 reaching $90 per MWh in August of 2022.

The Companies have discussed rising coal prices occurring at the same time that they finally attempted to replenish their coal stockpiles. The Commission recognizes the fact that coal costs were increasing. However, we have taken that into consideration in our calculations, and will not use higher priced coal as a reason to disallow any of the ENEC costs reported by the Companies. The Coal Report data we use clearly shows that new coal contracts were at prices that were in excess of historical coal prices. In some cases, coal purchases detailed in recent Coal Reports reached and exceeded $100 per ton. With coal purchased in 2022 at prices well in excess of historical values, the calculated variable production cost increased from below $30 per MWh in December 2021 to $40 per MWh in December 2022. While this is a significant increase in production costs, over the same period PJM energy market prices increased from around $30 per MWh to $80 per MWh (after peaking in excess of $90 per MWh in August, 2022). Thus, even with higher coal costs, the Companies would have benefitted from relatively low cost self-generation to serve internal load and increased margins on net system sales. Those benefits would have been passed-on to customers as lower net ENEC costs. That did not happen. Clearly, the Companies' efforts to utilize the coal-fired power plants - touted by them as a hedge against volatile PJM prices- were too little and too late.

As an example of the magnitude of the excess PJM prices and their impact on ENEC costs, the Amos plant is capable of outputting to the grid approximately 440,000 net MWh per week after taking plant load and losses into consideration. The Mountaineer plant is capable of outputting approximately 200,000 net MWh per week. When the difference between generation costs and PJM market prices is just $10 per MWh, failure to generate from these plants costs the Companies (and ultimately the customers) approximately $6.4 million per week either in excessive purchased power costs or lost margins. When the PJM price excess over production costs differential rose as high as $60 per MWh in the summer of

2022, the excessive purchased power costs or lost margins would have been as high as $38 million in a single week. Throughout 2021 and particularly in 2022, every day of down-time, de-rating, scheduled outage, extended outages, or bids designed to limit or eliminate dispatch of the Companies' power plants by PJM due to lack of adequate coal supplies that caused the West Virginia power plants to be under-utilized and in some cases not utilized at all for weeks at a time, was a lost opportunity to earn positive margins and lower the Companies' ENEC costs.

As discussed earlier, the Companies had a responsibility to manage their coal contracts to assure an adequate supply of coal under contract and structure incoming coal supplies to replenish stockpiles as they were used. Such management would allow increasing self-generation to offset high cost incoming power serving load. Yet, throughout this proceeding, the Companies' defense of the under-recovery is that they could not have increased self-generation to offset the incoming power necessary to serve load because they did not have sufficient stockpiles of coal and incoming coal supply. That defense merely highlights that the cause of the growth in ENEC under-recoveries traces back to poor and imprudent management and maintenance of adequate coal stockpiles.

During this proceeding, the Companies have maintained that they did not have sufficient stockpiled coal or incoming supply when needed but have taken steps to contract for future coal supplies that would be sufficient to replenish stockpiles as needed. They have expressed concerns with Commission reaction to the fact that the new coal supplies are more expensive than historical coal supplies. We do not dispute that coal costs increased in 2021 and 2022 and it was necessary to reflect the increases in new contracts. We do not criticize the contracts or restrict recovery of the cost of new coal supplies through our disallowance of a portion of the ENEC under-recoveries in this case. In fact, had the Companies reacted sooner and acquired even more new coal supplies its under-recovery would have been less and it would be facing less of a cost recovery disallowance. Nor do we question PJM LMPs. Our adjustment to the allowable ENEC under-recovery is due to the imprudent decisions and management that resulted in insufficient stockpiles of coal to self-generate more energy to serve load and possibly to have excess energy to sell in the PJM market.

We expect the Companies to consider 2021 and 2022 a lesson learned, to honor those new coal contracts, and negotiate more contracts when needed to allow them to maximize use of their power plants, both daily and hourly, as well as to provide a physical hedge against volatile purchased power prices. However, while the Companies may have modified their practices to assure adequate supplies of fuel and adequate inventory levels in the future, we cannot disregard or excuse the past practices that led to a catastrophic level of net ENEC costs and under-recoveries from March 2021 through February 2023. We will not allow full recovery of those costs.

With this background and the Commission's conclusion that the Companies' (1) failure to maintain adequate coal inventories at levels that allow them to fully operate their plants at high capacity factors when it was economical to do so; (2) failure to bid into the PJM Market in a manner that would assure maximization of net margins on net PJM transactions; and (3) failure to flexibly reschedule outages when market conditions, made it obvious that extending outages was unreasonable and imprudent in face of skyrocketing net ENEC costs due to over-reliance on external power in lieu of economical self-generation, the Commission will quantify the extent of excess ENEC costs or lost margins that should be imputed and offset against deferred ENEC costs.

For our calculation we begin with post-hearing Exhibit 4, which the Companies filed in response to a Commission request to document their market bids and cost-based bids into the PJM market, the corresponding LMP clearing prices, and the resulting market clearing volumes of their self-generation. The Companies' filed this data in three spreadsheets labeled: "Market Data - Mar 2021 to Feb 2022 CONFIDENTIAL; Market Data - Mar 2022 to Feb 2023 CONFIDENTIAL; and Market Data - Mar 2023 to July 2023 CONFIDENTIAL. Companies' Sept. 15, 2023 filing. For purposes of our calculations in this proceeding, which covers the review periods from March 1, 2021 through February 28, 2023, we use the data from the first two spreadsheets.

In these spreadsheets the Companies detailed hourly values for each day of the indicated periods. For each generation unit these hourly data were divided into:

> Date; Hour of the day; Market Offer; Cost-Based Offer; Net Available Capacity; MWh Sold to PJM; and DA LMP[17].

Using this historical data, the Companies calculated an hourly value at each generating unit for what they labeled:

> Winners Only Additional Margin; Winners Only Additional MWh; Full Out Additional Margin; and Full Out Additional MWh.

To calculate "Winners Only Additional MWh" the Companies first determined whether the hourly LMP was above the amount that they bid as their "Cost-based

[17] PJM has a Day Ahead (DA) Energy Market and a Real Time Market. Efficient operation of coal-fired power plants to maximize their use requires bidding and planning generation on a day-ahead basis.

Offer."[18] If the LMP was above their "implied cost" they considered that additional generation in that hour would have been a "winner." In those hours that were "winners" with LMP being higher than their cost-based offer, or implied costs, the Companies determined the amount of additional MWh by subtracting the amount sold to PJM from the amount available as shown in the column they labeled "Net Available Capacity." To determine "Winners Only Additional Margins", they then multiplied the additional MWhs that could have been sold into the PJM Market by the increment of the PJM LMP for each hour over the cost-based offer. The following Table (Table 4) is an example of the structure and calculations in the Companies' filing. We do not show the actual values in this example, but show the structure of the calculations that the Companies made. We will subsequently use the Companies' methodology, but will modify the Companies' cost numbers for reasons we will explain supra.

Table 4

Line	Unit	Date	Hour	Market Offer	Cost-Based Offer	DA LMP	Potential Margin per MWh	Winner For Generation (Y) or (N)	Net Available Capacity	MWh Sold to PJM	Winners Only Add'l MWh	Winners Only Add'l Margin
1	Amos 1	xxx	#	$110.00	$45.00	$40.00	($5.00)	N	750	600	0	$0
2	Amos 2	xxx	#	$100.00	$42.00	$44.00	$2.00	Y	750	400	350	$700
3	Amos 3	xxx	#	$105.00	$42.00	$65.00	$23.00	Y	1,300	300	1,000	$23,000
4	Mtr	xxx	#	$0.00	$0.00	$65.00	$65.00	?	0	0	0	$0
5	Mtr	xxx	#	$0.00	$0.00	$65.00	$65.00	?	0	0	0	$0
6	Mtr	xxx	#	$75.00	$75.00	$65.00	($10.00)	N	1,300	0	0	$0
7	Mtr	xxx	#	$125.00	$100.00	$75.00	($25.00)	N	1,300	0	0	$0
8	Amos 3	xxx	1	$100.00	$115.00	$75.00	($40.00)	N	1,300	0	0	$0
9	Amos 3	xxx	2	$100.00	$115.00	$73.00	($42.00)	N	1,300	0	0	$0
10	Amos 3	xxx	3	$100.00	$115.00	$78.00	($37.00)	N	1,300	0	0	$0
11	Amos 3	xxx	4	$100.00	$115.00	$70.00	($45.00)	N	1,300	0	0	$0
											Total	$23,700

Performing similar calculations for 8,760 hours per year at each generating unit for the period March 2021 through February 2023, the Companies calculated that selling additional MWh for periods when their cost-based offer was lower than the PJM LMP would have resulted in selling a significant number of additional MWh and the calculated Winner Only Additional Margins on a total company basis would have been nearly $130 million.

For purposes of our analysis of ENEC costs that would have been avoided by maximizing self-generation there are several factors in the Companies' derivation of the nearly $130 million Total Company "Winners Only Additional Margins" (or additional margins that would have occurred if all available power in every hour when their generation costs were lower than the market clearing price

[18] We put "cost-based" in quotes because, as we will address later, some of these offers escalate out of proportion to changes in coal costs in certain months to such degree that we cannot accept them as the true variable cost of generation. We will refer to the "cost-based" offer as an "implied cost" but do not accept all of the implied-costs as being representative of true incremental variable costs.

was dispatched or scheduled as "must run") that we do not accept as being reasonable.

First, we note that the Companies have used cost-based bids rather than true variable costs for purposes of their calculations. In many instances, the representation of costs as reflected in the Companies' cost-based bids appears to be reasonable and rational. In some instances, however, their cost-based bids cannot be explained by any evidence that the actual incremental variable cost of generation could fluctuate as much as the Companies reflect. While we asked the Companies to document their market and cost-based bids that would control signals to be dispatched into the PJM market, there has been significant emphasis and testimony in these proceedings that adders to implied cost of generation that do not represent true incremental variable costs do not provide a realistic representation of the margins that can be achieved from self-generation. Even witnesses for the Companies admitted that instead of representing variable costs, adders were a tool to restrict dispatch of generating units. For example:

> [T]he Company started using adders, which is an attempt to conserve coal for when it's more valuable in the future.

Testimony of Jeff Plewes, Sept. 5, 2023 Hearing Tr. at 197.

> So what you do, this is again why I think that adders were well done, is that you ensure that you don't generate when prices are lower than you expect the prices to be in the future in the market.

Id. at 214.

> So for example, if prices are, say, at $80, as they were in October . . . wouldn't it be great to just burn as much coal as possible . . . because every megawatt hour you generate with your coal is giving you a savings for your customer over getting it in the market. But if your coal is constrained, you have to think about, well, what happens if in December and January, for example, when prices are expected to be higher. . . . What if the power prices are $200, as they exceeded later in 2022? . . . if you burn it to save some consumers some money in October, and you don't have a way to replace it, and you're not available when you call for an event, thousands of dollars per megawatt hours lost. And so what you do is you put in adders. You don't just take the units out, you put in adders that represent the opportunity cost of that coal in the future.

Id. at 214-215.

This testimony, while applauding the Companies' efforts to conserve coal by putting adders on their "cost-based" bids to reduce the likelihood of getting into the market, demonstrates that the failure to minimize market purchases and to maximize self-generation was a direct result of a failure to maintain adequate coal stockpiles and incoming coal supplies to self-generate even when doing so could reduce ENEC costs.

While PJM market rules may allow adders other than incremental variable costs, such adders result in a number that does not represent the true incremental variable cost of generation. A fixed cost adder to a cost-based bid, even if allowed by a PJM tariff, does not make that fixed cost adder a variable cost that will be incurred on each additional unit of production. Although FERC has allowed fixed cost adders to energy cost bids, there was significant opposition to such adders from the PJM Independent Market Monitor and others, explaining why energy market cost-based bids should be based on the true marginal variable cost of generation.[19]

In the bid data filed by the Companies we find instances where the cost-based offer jumps from the range of $45 per MWh to over $100 per MWh in a three- or four-month period. Whether that is due to adders to the cost-based bid, or some other calculus adopted by the Companies, we find that level of "cost of generation" is unlikely and unreasonable. Thus, if the generation had been dispatched at the more realistic $45 per MWh true variable cost, the margins earned by the Companies would be significantly higher than the computed "winner only margins" that are based on the difference between the PJM LMP and the representation of variable costs embodied in the implied costs used in the Companies' calculations.

We find instances when the Companies' cost-based offers exceed $65 per MWh for extended periods of time. As we review the implied cost of generation as compared to increases in reported fuel costs, we do not find any months in which

[19] The [Independent Market Monitor] IMM and PJM Load Coalition oppose PJM's proposal [for certain maintenance adders] and argue that major maintenance costs incurred as a result of electric production should be recovered in the capacity market, and not the energy market, because they are not short-run marginal costs. The IMM explains that short-run marginal costs consist of fuel and variable operation and maintenance costs associated with other consumables used at the time of electric production... The IMM explains that ... it is not necessary to incur any specific maintenance expenditure to produce power in the short run because a resource does not consume a defined amount of maintenance parts and labor in order to start or produce additional MWh. FERC Order, Docket Nos. ER19-210-001, EL19-8-000, EL19-8-001, ORDER ON PROPOSED TARIFF AND OPERATING AGREEMENT REVISIONS (Issued April 15, 2019). 167 FERC ¶ 61,030.

the variable cost of generation should have exceeded $50 per MWh, even after reflecting coal purchases that sometimes exceeded $100 per ton. By representing cost of generation as equal to their cost-based bids, or implied costs, when some of those implied costs are not true variable costs and are inconsistent with the cost of fuel delivered and handled at the individual plants plus the cost of consumables, the calculations that the Companies made of "Winner Only Additional Margins" are understated.

We will base our initial months' calculations on the apparently reasonable and "truly variable," cost-based bids that were used in early 2021 as found in the Companies' post-hearing exhibit 4 filed on September 15, 2023. However, in place of excessively increasing implied costs used by the Companies, we will adjust the generation costs based on the increasing purchased fuel costs, including transportation and handling, throughout 2021 and 2022 when the costs as implied by the Companies in their cost-based bids are out of line with any reasonable expectation of increased costs of generation that can be explained by actual increased coal prices as reported in the monthly coal reports.[20]

Table 5 below shows the additional margins from additional generation in lieu of market purchases that the Companies would have achieved from March 1, 2021, through February 28, 2023, as calculated by the Companies. We also show the calculation made by the Commission based on the methodology used by the Companies but adjusting the cost of generation to reflect cost of generation based on increased coal cost reported by the Companies over that period of time. We determine that the sudden and irregular increases in implied generation costs used by the Companies are unreasonable and cannot be justified based on the cost of coal being acquired by the Companies at each of their generating plants over the calculation period. We show only the totals in Table 5 below.[21]

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[20] We note that the Companies have argued that their own example of $130 million total Company increased margins, or any calculation of potential increased generation if their bidding had reflected lower costs than PJM market clearing prices, is flawed because they did not have sufficient coal supplies to actually generate the energy that would have been scheduled from its plants. However, this argument is circular and not appropriate for purposes of our disallowance calculations because we have determined that there were unreasonable and imprudent decisions by the Companies that led to that shortage of adequate coal supplies. If the Companies had maintained adequate coal supplies more reasonably and prudently, they should have been able to clear the market at the levels we have calculated and would have benefitted by lower cost power for internal load and would also, at times, generated additional margins from net system sales, which would have further reduced the net ENEC costs for the period March 1, 2021, through February 28, 2023.

[21] The Table 5 calculation for Amos and Mountaineer lost margins are allocated to West Virginia jurisdictional operations of APCo at a 41.4 percent average allocation factor. The data filed by the Companies for the Mitchell units reflected only the Wheeling share of the Mitchell output and potential output. Therefore, no ownership allocation of the Mitchell lost margins was necessary.

Table 5

Twelve Months March 1, 2021 Through February 28, 2022								
Basic Data Filed By Companies				Companies' Calculations		Commission Calculations		
Unit	Date	Company Implied Cost Per MWH	DA LMP Per MWH	Winners Only Add'l Margin	Winners Only Add'l MWh	PSC Adjusted Cost Per MWH (Using Lower of Company Implied Cost or Calculated Cost from Coal reports)	PSC Adjusted Winners Only Add'l Margin	PSC Adjusted Winners Only Add'l MWh
Total Amos 1 Add'l Margin				$7,735,918	529,656		$15,389,979	834,695
Total Amos 2 Add'l Margin				$6,961,732	472,785		$13,205,246	666,111
Total Amos 3 Add'l Margin				$8,134,580	705,062		$16,168,206	928,124
Total Mtr. Add'l Margin				$7,735,918	529,656		$11,797,407	762,083
Total Amos and Mtr Add'l Margin				$30,568,148	2,237,160		$56,560,838	3,191,014
Total Mitchell 1 Add'l Margin				$2,665,454	167,031		$7,736,229	409,337
Total Mitchell 2 Add'l Margin				$3,440,043	241,004		$8,020,645	364,551
Total Mitchell Add'l Margin				$6,105,497	408,035		$15,756,874	773,888
Grand Total All Plants Add'l Margin				$36,673,645	2,645,195		$72,317,712	3,964,902
Allocated to West Virginia								
Amos and Mountaineer 41.4%				$12,991,463			$23,416,187	
Mitchell 100%				$6,105,497			$15,756,874	
Total West Virginia				$19,096,960			$39,173,061	

Twelve Months March 1, 2022 Through February 28, 2023								
Basic Data Filed By Companies				Companies' Calculations		Commission Calculations		
Unit	Date	Company Implied Cost Per MWH	DA LMP Per MWH	Winners Only Add'l Margin	Winners Only Add'l MWh	PSC Adjusted Cost Per MWH (Using Lower of Company Implied Cost or Calculated Cost from Coal reports)	PSC Adjusted Winners Only Add'l Margin	PSC Adjusted Winners Only Add'l MWh
Total Amos 1 Add'l Margin				$15,800,281	733,100		$65,716,683	1,865,717
Total Amos 2 Add'l Margin				$22,192,330	1,096,015		$78,892,894	2,266,261
Total Amos 3 Add'l Margin				$18,011,096	356,406		$56,780,352	1,602,989
Total Mtr. Add'l Margin				$7,992,064	379,432		$71,515,811	2,129,766
Total Amos and Mtr Add'l Margin				$63,995,770	2,564,954		$272,905,740	7,864,732
Total Mitchell 1 Add'l Margin				$9,907,127	349,532		$34,806,549	916,481
Total Mitchell 2 Add'l Margin				$17,059,473	485,743		$44,806,844	895,804
Total Mitchell Add'l Margin				$26,966,600	835,275		$79,613,393	1,812,286
Grand Total All Plants Add'l Margin				$90,962,370	3,400,228		$352,519,133	9,677,018
Allocated to West Virginia								
Amos and Mountaineer 41.4%				$27,198,202			$112,982,976	
Mitchell 100%				$26,966,600			$79,613,393	
Total West Virginia				$54,164,802			$192,596,370	

Twenty Four Months March 1, 2021 Through February 28, 2023					
Total Amos and Mtr Add'l Margin		$94,563,918			$329,466,578
Total Mitchell Add'l Margin		$33,072,097			$95,370,267
Grand Total All Plants Add'l Margin		$127,636,015			$424,836,846
Allocated to West Virginia					
Amos and Mountaineer 41.4%		$40,189,665			$136,399,163
Mitchell 100%		$33,072,097			$95,370,267
Total West Virginia		$73,261,762			$231,769,431

The summary provided in Table 5 should suffice to provide an understanding of the Commission calculations. The actual calculations encompass 8,760 hourly observations per year, over two years, at each of the six coal-fired generating units (three Amos units, one Mountaineer unit and two Mitchell units), or 105,120 lines of data. Each line includes six calculations for a total of over 630,000 calculated results. The Commission usually provides its calculations underlying decisions in tables within its orders or on appendices. In this case, the tables would cover over 1,500 properly formatted pages. Therefore, we will present the hourly calculations in a spreadsheet detailing the calculations instead of on printed tables. Initially, because the calculations contain variables that the Companies have labeled as confidential, we will provide the detailed calculations made by the Commission on a confidential DVD disk. A copy will be provided to the Companies with the issuance of this Order. Other parties to this case may request a copy which the Commission may provide upon request, providing that the party documents that it has entered into an appropriate Confidentiality Agreement with the Companies.

Based on our calculations as explained above and summarized in the Table 5, shown above, the Commission determines that if the Companies had planned and operated prudently, they could have reduced their West Virginia jurisdictional ENEC costs by $231,769,431. We will reduce the under-recovery for the period March 1, 2021, through February 28, 2023, that is allowable for ratemaking purposes, by $231,769,431.

In reaching this decision, we have fully considered the arguments and testimony of the Companies regarding the unexpectedness and exigency of the situation they found themselves in when market prices skyrocketed, and they were caught with insufficient coal supply to maximize their use of their lower cost generation. We have also considered the Companies' arguments regarding the prudence of their actions. As discussed above, we cannot agree that the Companies are blameless and without fault in building up an ENEC under-recovery of over $550 million. Having fully considered those arguments and all testimony offered by the Companies we determine that the costs incurred were unreasonable and the result of imprudent decisions, actions, and inactions, and have, therefore, quantified a disallowance amount of $231,769,431.

We have also fully considered the disallowances recommended by other parties. The methodologies for calculating those disallowances will not be adopted by the Commission. Instead, we use a detailed calculation of additional margins that could have been achieved as compared to what actually happened, as recommended by Company witness, Mr. Plewes.[22] We have, however, considered

[22] So I heard him [Mr. Ferrer] refer to it, his calculation, as simplistic, which is actually what I called it as well. I don't think that's a good thing when hundreds of millions of dollars [are] on the line to have something

all of the arguments and evidence presented by the parties addressing the reasonableness of the incurred ENEC costs and the prudence or imprudence of the Companies' actions or inactions.

Our calculation and disallowance of $231,769,431 does not take into consideration that the power plants were offline and unavailable for generation at times when market prices were very high and there was no effort by the Companies to expedite repairs or upgrades, or forego deferrable maintenance to return the plants to operational status in face of those high PJM market prices. The testimony by witnesses for the Companies indicates that return to service was possible, but that the Companies maintained the out-of-service status due to insufficient coal supplies. Thus, we could calculate additional lost margins during those periods but have not done so for purposes of this Order. Instead, in recognition of the very high remaining under-recovery balance and the likelihood that the imprudence in fuel planning, fuel practices and market strategies that caused a lack of adequate coal supplies, contributed to the inability or unwillingness of the Companies to offset a portion of the remaining $321,106,227 under-recovery by different decisions for taking or keeping plants out-of-service, we will defer any recovery of the remaining balance until September 2024. At that time, subject to review of the methodology and amount of the annual amortization in the next ENEC case, as discussed below, we will allow recovery of the remaining portion of the under-recovery in the amount of $321,106,227 over a ten-year period at a carrying charge rate of four percent per year beginning September 1, 2024.

Accordingly, the requested under-recovery balance of $552.9 million will not be fully allowed for recovery in rates. Instead, $231.8 million will be specifically disallowed for reasons explained herein. The remaining balance, currently $321.1 million, will continue to be deferred until September 1, 2024, at which time we will allow amortization through rates over a ten-year period. The calculation of the carrying charge will begin on September 1, 2024, and be applied to the unrecovered amount net of income taxes. A levelized amortization is preferable, but we will consider a straight-line amortization over ten years with a declining annual carrying charge if the Companies propose something other than a levelized annual amortization. In the next ENEC case the Companies will present their

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simplistic. There are better ways to do this calculation. But first of all, before I even say anything about that, talking about recommendations, my recommendation is no disallowance because I haven't seen anything that's [imprudent.] ...

But if it were to be found that there was [imprudence] I think that any disallowance calculation should follow some very basic principles. First of all, you'd have to determine what was even imprudent in the first place, what decision it was that they are finding imprudent and then finding out what the impact of that imprudency was and then comparing that to what actually happened. Right. It's very simple. It's used all the time. Mr. Plewes Testimony, Sept. 5, 2023 Tr. at 183-84.

proposed rate increments for the amortization of the under-recovery and other parties may address the calculation of the amortization of the under-recovery and class rate increments.

III. Proposed Stipulated Resolution.

The Commission has considered the proposed resolution of this case as filed in a stipulation among the Companies, the WVEUG, and the WVCA. Stipulation, Dec. 27, 2023. The Stipulation proposes that the Companies will absorb $50 million of its requested $553 million under-recovery, leaving $503 million to be securitized. The securitization is intended to make a net $503 million price tag more palatable to customers, however, it is still a reward for the Company which will receive $503 million in upfront cash upon the sale of the securitized bonds. The precise annual revenue requirement for a $503 million securitized 20-year bond issuance is unknown at this time. Based on Mr. Scalzo's estimates presented in his Direct Testimony, after reducing the under-recovery portion of the securitization by $50 million, we can calculate an annual revenue requirement of $41 million for a twenty-year securitization. Customers would be paying that amount through a non-bypassable rate increment for twenty years. The total amount paid by customers will be $820 million.

We understand that the intent of the Stipulation is to bundle the securitized $503 million net under-recovery with unrecovered investment in the Amos and Mountaineer power plants. This additional amount is estimated by Mr. Scalzo to be approximately $1.2 billion. Under the securitization proposal the Companies would be rewarded for their imprudent management of their power plants by receiving an upfront cash payment of $1.2 billion from the bond receipts. The Companies argue that they will be giving up the earnings they presently receive on the investment in Amos and Mountaineer; but these foregone earnings would come with a check for $1.2 billion that could be reinvested in whatever profitable assets they, or AEP, propose to invest in. Customers will be obligated to pay approximately $98 million per year for 20 years, or a total of $1.9 billion to fund the $1.2 billion up-front payment to APCo for the Amos and Mountaineer power plants. In effect, customers will "buy" the West Virginia share of the plants for $1.9 billion, but APCo will retain ownership.

The securitization proposed in the Stipulation would also hand another $88 million up-front payment to the Companies for past expenses that have been deferred on their books.

In total, based on the Companies' estimates presented by Mr. Scalzo, adjusted for the $50 million reduction in ENEC under-recovery allowance, the Stipulation would require a debt commitment by the customers that would result in a non-bypassable rate requirement of approximately $147 million per year for 20 years. Customers will pay a total of over $2.9 billion over the expected twenty year term of the securitized bonds.

We understand the hope that the annual revenue requirement on securitized bonds for the power plants will be less than the current capital costs of the rate base value of the power plants and will offset the revenue requirements on the $503 million under-recovery proposed in the Stipulation and the $88 million other securitized costs. It is more than likely that securitizing the unrecovered investment in the power plants would result in an offset greater than the rate base cost of service on the power plants. There is no assurance, however, that the combination of bond payment requirements and base rate offsets would be a zero-sum game if the securitization were finalized.

There are many good intentions in the Stipulation and certain benefits for the Companies. It is certain that the Companies will voluntarily waive recovery of $50 million of their requested $553 under recovery. In return, it is certain that the Companies would receive an immediate $503 million cash payment for under-recoveries that we have determined contain at least $232 million in unreasonable costs incurred due to imprudent management by the Companies. It is certain that the Companies would also receive an immediate cash payment for around $88 million for deferred costs. It is certain that to give the Companies these cash payments, totaling $591 million, would obligate customers to pay non-bypassable debt service payments that will likely be approximately $49.2 million per year, or $984 million over 20 years. It is certain that the debt service revenue requirements on the $1.2 billion securitized unrecovered investment in Amos and Mountaineer will likely be approximately $147 million per year for 20 years, and that debt service will be lower than the capital rate base/rate of return revenue requirements on the unrecovered investment in Amos and Mountaineer. It is uncertain, however, how much lower the revenue requirements will be and the extent to which that would offset the debt service on the securitized under-recovery and deferred costs.

Admittedly, there is a price tag of the decision to disallow $231.8 million of the under-recovery and allow the balance of $321.1 million to be recovered over ten years beginning September 2024. With the four percent carrying charge authorized in this Order, the allowable under-recovery will carry a price tag for customers of about $39 million per year. This level of recovery will last for ten years, rather than a higher amount proposed in the Stipulation lasting for 20 years.

The result of our decision today will cost an average 1,000 KWh per month residential customers approximately $2.50 per month for ten years. The Stipulation would cost an average 1,000 KWh per month residential customer around $3.17 per month for twenty years for the under-recovery and deferred cost components. To offset the $3.17 per month rate impact of the under-recovery and deferred cost cash payments to the Companies, the Stipulation does offer the potential benefit of an offsetting revenue requirement for the securitized unrecovered cost of Amos and Mountaineer that will be lower than the traditional rate of return revenue requirements on the rate base value of Amos and Mountaineer.

We have considered the Stipulation's proposal and are concerned that it rewards the Companies in spite of their unreasonable and imprudent actions, in return for the potential benefits of an offset for lower capital costs related to the unrecovered cost of Amos and Mountaineer. Given the currently unknown net results of a securitization and the fact that the securitization would include an immediate $503 million cash payment to the Companies for their stipulated under-recovery at a cost to customers of $41 million per year for twenty years, as measured against a known $31.1 million (plus a carrying charge) annual cash payment to the Companies over ten years for the allowable under-recovery as ordered herein, we find that the stipulated resolution is not a fair and balanced outcome.

IV. Motions for Protective Treatment.

In the 2023 ENEC, the Companies filed a Motion for Protective Order on May 5, 2023, and addenda to that motion on August 18, 2023, and September 22, 2023. The Companies filed the following information under seal in conjunction with these motions: Exhibits RRS-D attachment (att.) 2, KKC-D atts. 2 and 3, SAS-D att. 4, TCK-D att. 1, and JMS-D att. 2, JJS-SD att. 2, and post-hearing exhibit 4.

It is not necessary to rule on the Motions for Protective Treatment at this time. The documents filed under seal are in the custody of the Executive Secretary and the Commission will continue to maintain the confidentiality of those documents. Upon the filing of a West Virginia Freedom of Information Act (WV FOIA) request for the sealed information, pursuant to W. Va. Code § 29B-1-1 et seq., the Commission will notify the Companies and will provide an opportunity to present arguments regarding continued protective treatment. Any parties in possession of any confidential material shall maintain the confidentiality of that information until further order.

FINDINGS OF FACT

1. The Companies had insufficient supplies of coal inventory during the period in question.

2. In July 2021, coal stockpiles were declining yet the Companies took no action to replenish the stockpiles until September 20, 2021, when they issued an RFP for additional coal supply.

3. The PJM market prices, using Day Ahead PJM Energy prices for the Amos Plant, had climbed from near $20 per MWh in 2020 to $23.81 per MWh in 2021 (a 19 percent increase), then to $34.87 per MWh in July 2021 (an additional 46 percent increase), and were on an upward trajectory that would eventually peak at $91.88 per MWh in August 2022 (an additional 163 percent increase).

4. During the two year review period of March 1, 2021 through February 28, 2023, the Companies had the lowest level of generation in the past twenty years.

5. Also during the two year review period, the PJM market prices spiked to the highest level in the last twenty years.

6. The Day-Ahead average PJM system-wide LMP moved from an average of $21.20 per MWh in 2020 to $39.37 per MWh in 2021 and $75.44 per MWh in 2022. Table 1.

7. Based on past generation levels, Amos, Mountaineer, and Mitchell power plants are capable of generation far in excess of the generation levels they achieved in 2021 and 2022.

8. As PJM prices climbed from $21.40 per MWh in 2020 to $39.37 in 2021, the Companies' coal burn and related MWh generation at their power plants increased only slightly. Table 2.

9. When the PJM price climbed dramatically to an average of $75.44 per MWh in 2022, the Companies' coal burn and MWh output from their coal-fired generation plants decreased. Table 2.

10. The Companies did not make changes to their fuel procurement process or bidding into PJM to increase the capacity factors of their plants during the period March 1, 2021 through February 28, 2023.

11. Mr. Dial, who was employed by American Electric Power Service Corporation to manage fuel procurement for the Companies, was unaware of the 69 percent generating rate identified by the Commission in its September 2, 2021 Order in the 2021 ENEC.

12. Generation of net system sales (wholesale sales in excess of purchases that produce net positive margins) has always been a goal that we have stressed that the utilities must maximize. Appalachian Power Co., Case No. 83-697-E-42T, Comm'n Order, Sept. 28, 1984, at pp. 15-17.

13. The Commission never suggested to the Companies in any previous ENEC orders, or any orders, that they should forego having sufficient fuel inventories, having sufficient coal under contract, prudently bidding into the PJM market, and operating power plants to maximize their economical coal-fired generation over a daily LMP curve.

14. Even with new coal contracts at prices well in excess of historical price levels, self-generation from the Companies power plants would have reduced ENEC costs as that self-generation displaced high-priced PJM energy costs.

15. The narrow differences between PJM market prices and the Companies' production costs widened dramatically from early 2021 to December 2022 as the market prices increased at a greater rate than production costs. Table 3.

16. An approximate $20 per MWh increase in production costs pales in comparison to the PJM market price which jumped from approximately $30 per MWh in the spring of 2021 to $60 per MWh by November 2021, and then after a brief pull-back climbed in 2022 reaching $90 per MWh in August of 2022.

17. The Amos plant is capable of outputting to the grid approximately 440,000 net MWh per week after taking plant load and losses into consideration.

18. The Mountaineer plant is capable of outputting approximately 200,000 net MWh per week.

19. When the difference between lower generation costs and higher PJM market prices is just $10 per MWh, failure to generate at Amos and Mountaineer costs the Companies, and ultimately the customers, approximately $6.4 million per week either in excessive purchased power costs or lost margins.

20. Under the Stipulated settlement proposed by the companies and two parties to the case, the Companies would receive an immediate $503 million cash payment for under-recoveries that we have determined contain at least $232 million in unreasonable costs incurred due to imprudent management by the Companies. They would also receive an immediate cash payment for around $88 million for deferred costs.

21. To give the Companies proceeds from a $591 million securitized bond issue for their stipulated under-recovery and other deferred costs would obligate customers to pay non-bypassable debt service payments of approximately $49.2 million per year or $984 million over twenty years.

CONCLUSIONS OF LAW

1. The Companies have the burden of proving that their ENEC costs were reasonable and the result of prudent management of their generation assets, fuel supplies, and purchased power costs. 2021 ENEC, Comm'n Order, May 13, 2022, at 6.

2. While any contemporary action must be based on what is known or reasonably knowable at the time the action is taken, a continuum of actions leading up to a decision point must also be taken into consideration when determining prudency.

3. It is the responsibility of the Companies to assure that they can operate their own plants when the volatile energy market exposes them to high prices.

4. When utility management acts in an unreasonable and imprudent manner, the Commission has the authority to protect customers from the negative financial consequences of the utility's unreasonable actions or inactions. Lumberport-Shinnston Gas Co. v. Public Serv. Comm'n, 271 S.E.2d 438 (1980)(citing United Fuel Gas Co. v. Public Serv. Comm'n, 174 S.E.2d 304, 317, 154 W. Va. 221, 243 (1969)(citing Southern Bell Telephone and Telegraph Co. v. Georgia Public Serv. Comm'n, 49 S.E.2d 38, 66 (1948))).

5. Reasonable and prudent management must ensure not only that contracts are in place to cover a minimum 30-day aggregate coal supply for the remainder of the life of the generating plants, but also must ensure that the incoming coal supplies replace coal as it is used.

6. If the Companies had managed their coal stockpile levels reasonably and prudently, they would not have experienced the unreasonably low inventory levels that they now use to excuse their inability to maximize the use of their coal-fired power plants.

7. The Companies failed to manage their fuel supplies and power plant operations in a reasonable, prudent, and efficient manner during the time period March 1, 2021 through February, 2023.

8. In lieu of self-generation, the Companies' purchase of excess amounts of power from the PJM market at prices that were at the highest level in PJM History was unreasonable and the result of imprudent decisions regarding coal inventories, coal procurement, bidding into the PJM energy market, and minimization of out-of-service time .

9. If the Companies had planned and operated prudently, they could have reduced their West Virginia jurisdictional ENEC costs by at least $231,769,431 during the time period of March 1, 2021 through February 28, 2023.

10. Incurred costs of $231,769,431 were unreasonable and the result of imprudent decision, actions, and inactions by the Companies.

11. The Stipulation is not a fair and balanced outcome given the unknown results of a securitization that would include an immediate $503 million cash payment to the Companies for their under recovery when the Companies acted imprudently causing excessive ENEC costs that the commission has determined were a minimum of $231,769,431.

12. It is not necessary to rule on the Motion for Protective Order at this time.

ORDER

IT IS THEREFORE ORDERED that the Commission disallows $231,769,431 of the under-recovery requested by the Companies. The Commission approves the remaining approximately $321.1 million under-recovery to be recovered through an ENEC rate increment designed to recover that amount over ten years, including a 4 percent per year carrying charge, with both the rate increment and carrying charge beginning September 1, 2024.

IT IS FURTHER ORDERED that the Companies calculate the ENEC rate increment to recover the approximate $321.1 million under-recovery specified above plus the 4 percent per year carrying charge, and file that increment for consideration by the Commission in their next ENEC filing.

IT IS FURTHER ORDERED that the Executive Secretary hold the unredacted version of the information filed by the Companies and described in the Motion for Protective Order and addenda to Motion for Protective Order as confidential under seal, separate and apart from the remainder of the case file until the Commission receives and reviews a request for the information pursuant to WV FOIA.

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