COMMONWEALTH OF KENTUCKY
BEFORE THE
PUBLIC SERVICE COMMISSION OF KENTUCKY

In The Matter Of:

AN EXAMINATION OF THE APPLICATION)
OF THE FUEL ADJUSTMENT CLAUSE OF)
KENTUCKY POWER COMPANY FROM)CASE NO. 2014-00225
NOVEMBER 1, 2013 THROUGH)
APRIL 30, 2104)

ORIGINAL

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Transcript of November 12, 2014, hearing before David L. Armstrong, Chairman; James W. Gardner, Vice-Chairman; and Linda Breathitt, Commissioner, at the Kentucky Public Service Commission, 211 Sower Boulevard, Frankfort, Kentucky 40602-0615.

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* * *

VICE-CHAIR GARDNER: We're on the record. This is Case Number 2014-00225. By agreement, we're going to do the first part of the case just as we do all FAC cases, so we're swearing in folks as a panel, and so let's have appearances of counsel, please.

Mr. Overstreet.

MR. OVERSTREET: Thank you, Mr. Vice-Chairman. My name is Mark Overstreet with the law firm of Stites & Harbison, 421 West Main Street, Frankfort, Kentucky 40601. Appearing with me here today but not in connection with the panel is Kenneth Gish, Stites & Harbison, 250 West Main Street, Suite 2300, Lexington, Kentucky 40507.

VICE-CHAIR GARDNER: Thank you.

General.

MR. COOK: Good afternoon. On behalf of the Attorney General, Lawrence Cook. My cocounsel, Jennifer Hans and Greg Dutton, 1024 Capital Center Drive, Frankfort, Kentucky.

VICE-CHAIR GARDNER: Mr. Kurtz.

MR. KURTZ: Your Honor, for KIUC, Mike Kurtz, Kurt Boehm, Jody Cohn, Boehm, Kurtz & Lowry, 1510 URS Center, Cincinnati, Ohio. KIUC participating members in this particular intervention are Marathon

Ashland, AK Steel, Air Products, EQT Natural Gas. I'm drawing a -- I believe that's -- that's -- and maybe perhaps -- and Air Liquide I think as well. Thank you.

VICE-CHAIR GARDNER: Thank you.

MR. PINNEY: On behalf of the Commission, J.E.B. Pinney, Richard Raff, Quang Nguyen from the Office of General Counsel. Also Chris Whelan, Matthew Baer, and Leah Faulkner from the Department -- Division of Financial Analysis.

VICE-CHAIR GARDNER: Thank you. Has notice been given?

MR. OVERSTREET: Yes, Your Honor, notice has been given. It was filed of record on November 5th.

VICE-CHAIR GARDNER: Okay. Great. Thank you. Are there any pending motions?

MR. OVERSTREET: Yes, Your Honor. In addition to several motions for confidential treatment, Kentucky Power, in accordance with the Commission's regulation, has requested leave for -- to have the proceeding stenographically transcribed, and the Commission hasn't had an opportunity to rule on that motion yet, so I spoke with Mr. Pinney before the hearing began and he said I would not be presuming to have Ms. Kogut appear and transcribe the proceedings even though the Commission has not had a chance to rule yet.

VICE-CHAIR GARDNER: Okay.

MR. COOK: No objection to that motion.

VICE-CHAIR GARDNER: Any objection?

Okay. We'll go ahead and grant your motion for that.

MR. OVERSTREET: Thank you.

VICE-CHAIR GARDNER: Sure. Anything else?

MR. OVERSTREET: That's all we have pending, Your Honor.

VICE-CHAIR GARDNER: Okay. This time is for public comment. Again, this is Case Number 2014-225, Fuel Adjustment Clause proceeding for Kentucky Power. Is there any member of the public who would like to be heard?

Seeing none, Mr. Overstreet call your first witness.

MR. OVERSTREET: Thank you, Mr. Vice-Chairman.

Appearing today as part of the panel, to my immediate right is Charles West. To my immediate left is John Rogness. To his left is Dan Moyer, and to his left is Aaron Sink. Mr. Sink is the plant manager of the Big Sandy plant, Mr. Moyer is the plant manager of the Mitchell plant, Mr. Rogness is with Kentucky Power, and then Mr. West is with the Service Corp. and he handles fuel procurement.

VICE-CHAIR GARDNER: Thank you. Each of you-all who are going to testify if you would stand and raise your right hand, please.

* * *

CHARLES WEST, JOHN ROGNESS, DON MOYER, AND AARON SINK, called by Kentucky Power, having been first duly sworn as a panel, testified as follows:

DIRECT EXAMINATION

By Mr. Overstreet:

Q. Mr. West, did you cause to be filed in the record of this proceeding certain responses to data requests?

MR. WEST: I did.

Q. And do you have any corrections or changes to those responses?

MR. WEST: No, I do not.

Q. And if you were asked those questions today, would your answers be the same?

MR. WEST: They would.

Q. And, Mr. Rogness, did you cause to be filed in the record of this proceeding certain responses to data requests?

MR. ROGNESS: I did.

Q. Have you had any change -- corrections or changes to those responses?

MR. ROGNESS: I do not.

Q. Mr. Moyer, did you cause to be filed in the record of this proceeding certain responses to data requests?

MR. MOYER: I did.

Q. And do you have any corrections or changes?

MR. MOYER: No, I do not.

Q. And if you were asked those same questions here today, would your answers be the same?

MR. MOYER: Yes, they would.

Q. And, Mr. Sink, did you cause to be filed in the record of this proceeding certain responses to data requests?

MR. SINK: I did.

Q. And do you have any corrections or changes?

MR. SINK: No, sir.

Q. And if asked the same questions, would your answers be the same?

MR. SINK: Yes, they would.

MR. OVERSTREET: Witnesses are available for cross-examination.

VICE-CHAIR GARDNER: Okay.

MR. COOK: Your Honor, if I would, by

agreement of counsel, we are going to allow KIUC to proceed first.

MR. KURTZ: No questions for the panel.

MR. COOK: No questions.

CROSS-EXAMINATION

By Mr. Pinney:

Q. Good afternoon.

MR. WEST: Good afternoon.

Q. Please refer to the response to Item 1 of the first Commission Staff data request. And in Kentucky Power's two previous FAC cases, which were cases 2013-444 and 2013-261, there were no spot purchases shown, but in response to Item 1 of the first data request, it shows that there are 79 percent contract purchases and 21 percent spot purchases.

Now, is the increase in spot purchases due to the upcoming retirement of Big Sandy Unit 1 -- or 2 and the conversion of 1?

MR. WEST: In -- yes, in general. One, with Mitchell now on board, we tend to do a few more spot purchases on the Mitchell side than we did at Big Sandy, but even at Big Sandy, the burn there is -- over time we have found that the burn has been very unpredictable, and so we tend to buy to the low end to where we think the burn is going to be with either longer term or at least one-year deals or longer, and then we fill in with spot purchases as the burn actually takes place. And we saw that definitely in 2014, where we were projecting a much lower forecast burn at the start of the year than what we actually ended up getting.

MR. OVERSTREET: Mr. Pinney, may I interrupt to remind the witnesses to identify themselves --

MR. WEST: Oh.

MR. OVERSTREET: -- when they speak --

MR. WEST: I apologize.

MR. OVERSTREET: -- as a member of the panel.

MR. WEST: Thank you.

Q. Okay. Then I draw your attention to the response to Item 8, the first data request. And page 1 of 3, the Ohio Valley Resources contract. The response shows that the term of this contract is January 1, 2007, to December 31st, 2021, but the information you provided is only for 2014. So is the reason the information for years 2007 through 2013 not -- the reason it's not shown is because the contract is for the Mitchell Station?

MR. WEST: That contract -- well, Chuck West, or Charles West responding.

That contract is for the Mitchell Station.

Q. And it shows that Kentucky Power has only received 16 percent of the annual requirements under the contract for 2014. What is the status of this contract?

MR. WEST: And Charles West responding.

That contract -- we are a little behind on that contract as of today's date, and -- but we plan to carry over a significant amount of tonnage into next year, probably up to 400,000 tons.

Q. Okay. The first -- the same response, but page 3 of 3. And referring to the first Southern Coal Sales contract, the response says only 49 percent of the annual requirements were received in 2013.

Does Kentucky Power expect to make up the shortfall?

MR. WEST: Charles West responding.

We did provide -- you -- I'm sorry. You said the 2 -- you were talking about the 2013 tonnage of --

Q. Right. Only 49 percent --

MR. WEST: Yeah.

Q. -- was met.

MR. WEST: We did allow -- provide Southern with the opportunity to make up as much of those tons as they could in -- during the year. We don't think they're going to get it all made up, but we gave them the opportunity to.

Q. Okay. And that shortage didn't lead to any operational difficulties or shortfalls, did it?

MR. WEST: Charles West responding.

No, we were able to fill in with spot purchases.

Q. Okay. And please refer to the response -- and to follow up, you said you made -- you had spot purchases to make up for the shortfall in the contract purchases.

Were the prices for the spot purchases more than what the contract purchase price would have been?

MR. WEST: Charles West responding.

Yes, the price of the spot coal is actually lower than the -- than the contract. The price has gone down over the last year, so --

Q. All right. Now take -- please take a look at the response to Item Number 9 of the first data request, page 2 of 2. And the response states that in comparison, in the table at the bottom of the page, "Kentucky Power has the second lowest fuel costs for the review period."

However, taking a look at the table, Kentucky -- is there a utility missing from the comparison or should the responses say that Kentucky Power had the lowest fuel costs in comparison for the review period?

MR. WEST: I'm not -- could you restate that? I missed the utilities -- is there a utility missing, you asked?

Q. Well, there is -- it says, "In this comparison, Kentucky Power has the second lowest fuel costs for the review period on" -- compared to, I think -- on a cents per million British Thermal Units basis.

MR. WEST: Correct.

Q. You have the table at the top and the table at the bottom. And is there a utility missing from the comparison or should the responses state that Kentucky has the lowest fuel cost in comparison for the review period?

MR. WEST: Okay. So I'm little a confused. I show AEP Generation Resources at the bottom as the lowest cost.

MR. OVERSTREET: May I show him the response, Mr. Pinney?

Q. It's -- I do not show a --

MR. OVERSTREET: Yeah, that's why I wanted to show him the response.

MR. PINNEY: Okay. Yes, please. Sorry.

MR. WEST: Okay. I have -- yes, there is a -- I guess a utility got dropped off in the -- in the -- my table shows AEP Generation Resources as the bottom utility, with a cost of 262.12.

MR. PINNEY: Would you-all be able to provide that post hearing?

MR. OVERSTREET: Absolutely. And I apologize.

MR. PINNEY: All right. Thank you.

Q. All right. Please refer to the response to Item 11 of the first data request, and specifically 11 b., page 2 of 2. And there the Mitchell plant is shown as having 155,840 tons of high-sulfur coal and 243,973 tons of low-sulfur coal.

Can you confirm that these totals are for the Mitchell plant as a whole and not Kentucky Power's share of the coal?

MR. WEST: Charles West responding.

That's correct. It's for the Mitchell. We track the inventory for the whole plant.

Q. And then same response, same page, but subsection c. The response shows a target inventory of 15 days for Mitchell high-sulfur coal, but 30 days for Mitchell low-sulfur coal.

Can you explain why there are different target inventory dates based on the fuel type?

MR. WEST: Inventory -- yes. Charles West responding.

The target inventory days were established by our FSTG Committee, which looks at all the different types of coal we take into each plant, what the potential delays are, you know, the supply delays and transportation delays, and takes that all into contract when they determine the target inventory for each one of the -- one of the coal piles.

The high-sulfur pile itself, the mine is right next to the plant and the coal is just conveyored, is shipped over on a conveyor belt from the mine directly into the plant, so it's a very reliable source, and as a backup, if anything does happen to the mine or the conveyor belt, we can always bring in barge coal when we need to. So the reliability of that supply is very, very high, because there's a lot of -- even though the one mine right next door could have a problem, there are about four or five mines right in the area that we can take coal from, even under the same contract, because they are all owned by the same supplier.

Low-sulfur coal, of course, most of it comes off either Kanawha River or the Big Sandy River, and you have a lot more potential transportation problems, as we saw earlier this year, in the -- during the cold weather in the first three months of the year. I won't call it a polar vortex, I think that one's -- but the first three months of the year we had a lot of transportation problems getting the low-sulfur coal up to the Kanawha River and up to that section of the river, so the supply has a lot more potential disruptions. That's why it has a much higher target inventory level.

Q. In Case Number 2013-430 the Commission approved Kentucky Power's request to convert Big Sandy Unit 1 to a natural gas-fired facility.

What -- can you give us an update on the status of the project and expected completion date.

MR. WEST: Aaron, do you want to give that?

MR. SINK: Yes, sir. Aaron Sink responding.

The project is currently in the engineering and design phase with a scheduled completion of May 31st, 2016.

Q. Okay. And still referring to the response to the Commission's first data request, but item 20. The response states that the reason Oral Solicitation Number 2 was not written was because, and I quote, "Rail was unavailable at the time, so all suppliers who were known to have crushed coal deliverable by truck were solicited," end quote.

Kentucky Power was asked in its last FAC hearing whether it receives coal deliveries by rail at Big Sandy. The response was that it did not receive coal by rail in 2013 and there was some work needed on the rail line.

When this response states that rail was unavailable, does it mean that that work at the Big Sandy plant that was needed to repair it and that was referenced in the last FAC hearing had not been performed?

MR. WEST: That's correct. The rail -- there was pretty minor repair needed on the rail. We had a set of cars there at the time that we could have -- we could have gotten moved, but the reality was the price of rail coal was really out of the money at the time, so until -- what we did is, until rail coal got low enough that it was a player into the plant and the cost would be lower than the truck coal, we didn't -- we didn't bother doing any of the repair work on the tracks. Since then we've actually gone and repaired the tracks and have taken some rail coal in there.

Q. And I think I can ask this following question without having to go into confidential session, but refer -- I want to refer to the confidential response to this question, Attachments 1 and 2. Attachment 1 shows the bid analysis for coal for the Mitchell Station and attachment shows shows -- Attachment 2 shows the bid analysis for coal for Big Sandy. Is that correct?

MR. WEST: Yes, that's -- Charles West responding.

That is correct.

Q. And if that is the case, the response shows that the coal solicited for the Big Sandy station was cheaper than that for the Mitchell Station. And is it unusual for the Big Sandy coal to be cheaper than the Mitchell's -- Mitchell coal?

MR. WEST: Charles West responding.

It's not necessarily unusual. They both -- it's both very similar types of coal. We request -- coal into the Big Sandy plant is obviously trucked in, and it's priced off the same general index that the Mitchell low-sulfur coal is priced off. That --

the low-sulfur coal, though, has to have barges or it has to be barged from Kanawha River all the way up the Ohio River, so your transportation rate is typically a little higher than the trucked coal down at Big Sandy.

Q. And then skipping back, referring to the response to Item 4, the Commission Staff's first data request, and that show -- the response shows the capacity factor of 65.04 percent for the Mitchell Station from January through April of 2014.

Is that capacity factor typical for the Mitchell Station?

MR. MOYER: This is Dan Moyer responding for that.

It's typical to the low side. It would generally be just a little higher than that.

Q. Okay. And then why? Why would it be typically higher?

MR. MOYER: We had a number of outages through that period that would have driven that down for the capacity factor with -- and I think they were all in the reporting as well.

Q. Okay. Were they more forced or planned outages?

MR. MOYER: Forced.

Q. Okay. Please refer to Item 7 of the same response to the data requests, and I am looking at page 1 of 4. That shows that Big Sandy Unit 1 experienced a planned outage in November lasting three weeks for repair of the boiler and precipitator. The following April the same unit experienced a forced outage lasting almost two weeks and was listed for the same repair.

What was the issue in April, and was it related to something that was not repaired during the November outage?

MR. SINK: Aaron Sink responding.

It was just a continuation of the same repairs that were made in the November outage, nothing that was unresolved from that first outage in November.

Q. Okay. And then refer to page 3 of 4 of the same response. There are several outages shown as LP turbine bearing vibration for Mitchell Unit 1. In February there was a 384 planned outage -- hour planned outage for turbine bearing inspection and repair.

Did this repair fix the problem or have there been other bearing vibration problems since the repair?

MR. MOYER: This is Dan Moyer responding, first.

Yes, it did fix the problem, and it's been repaired since then completed.

Q. So now I ask to turn to Kentucky Power's responses to Commission Staff's third data request, and particularly the response to 1 c.

The response states, "Upon review and analysis the Company agrees that its earlier understanding of the EKPC Orders referenced in subpart (a) was mistaken."

So, given this statement, does Kentucky Power believe that $83,721 in purchased power costs should be disallowed for the period under review as this was the total that was identified by Kentucky Power in response to Item 8 b. (3) of this -- to the response to the third data request, meaning that that amount exceeded the amount of what had been recovered using the equivalent peaking unit method?

MR. ROGNESS: This is John Rogness.

Yes.

Q. And given that Kentucky Power now agrees that its understanding of the EKPC Orders referenced in subpart (a) was mistaken, is Kentucky Power currently limiting recovery of its purchased power costs through its FAC using the equivalent peaking unit method when it experienced a planned outage or is it not experiencing an outage -- if not experiencing an outage but must purchase power to meet the load?

MR. ROGNESS: We are performing the tests on all purchases to make sure that the economic -- the true economic cost is passed on to our customers.

Q. Using the peak -- peak equivalent?

MR. ROGNESS: Yes.

Q. Okay. So when did Kentucky Power begin doing this?

MR. ROGNESS: When we realized that our understanding of the orders was incorrect. So we performed the test on the six-month test period, and that's where --

Q. This six-month test period?

MR. ROGNESS: Yes.

Q. Okay.

MR. ROGNESS: But then we've also gone back and checked the previous two six-month periods, and in those two instances the purchased power cost was less than the peaking unit equivalent cost.

Q. Okay. Just to be a little more specific, you say you're currently using or Kentucky Power is currently using the peaking unit method. Was it as of the six -- six-month period when it began or when the response to the data request was filed?

MR. ROGNESS: Well, before we filed the response, when we realized that our interpretation of the orders was incorrect, then we went back and we performed the analysis.

Q. So after the response to the second data request and before the third? Okay.

MR. ROGNESS: Yes.

MR. PINNEY: All right. No further questions for the panel.

VICE-CHAIR GARDNER: Any redirect?

MR. OVERSTREET: I just have one question for Mr. West.

REDIRECT EXAMINATION

By Mr. Overstreet:

Q. Mr. West, the -- and I apologize, it got away from me, but you have a response in there where you list the contracts for -- that Kentucky Power currently contracts for the purchase of coal that Kentucky Power currently has outstanding?

MR. WEST: Uh-huh.

Q. Could you identify for the Commission which of those contracts is supplying coal to the Mitchell

Station?

MR. WEST: Just the contracts, not the spot purchases you're talking about?

Q. Just the contracts, yes.

MR. WEST: Okay. So the -- if you look at the one, two, three, four, five contracts, the Ohio Valley Resources is the -- on that list is the only one supplying coal to the Mitchell Station during this time.

I'm trying to find -- there was also a second Southern Coal Sales agreement that we had some carryover on, about 40,000 tons of carryover.

Q. Is one of the two Southern Coal Sales contracts supplying to Mitchell?

MR. WEST: Yes.

Q. And that coal is coming out of -- at least in part, coming out of Kentucky?

MR. WEST: Yes.

Q. And then the S. M. & J, you have two contracts?

MR. WEST: Oh, I'm sorry. Yes. The S. M. & J -- hang on. The second of the S. M. & J contracts that's FOB barge is coming out of Kentucky, and it's also a Mitchell contract.

Q. Okay. So you have two contracts for coal going into Mitchell?

MR. WEST: Well, that S. M. & J contract was just some carryover.

Q. Right.

MR. WEST: It's no longer --

Q. I understand. It's just some carryover, but it --

MR. WEST: Right.

MR. OVERSTREET: -- but that coal was coming out of Kentucky --

MR. WEST: Yes.

Q. -- and it went to Mitchell?

MR. WEST: Yes.

MR. OVERSTREET: That's all I have.

VICE-CHAIR GARDNER: Mr. Kurtz.

MR. KURTZ: Oh, nothing, Your Honor. No questions.

MR. COOK: Nothing, Your Honor.

MR. PINNEY: We're finished.

VICE-CHAIR GARDNER: Okay. Were there any post-hearing data requests?

MR. OVERSTREET: Yes, Your Honor. We were going to correct the response to the one data request that left off one of the --

VICE-CHAIR GARDNER: Right. Right.

MR. OVERSTREET: -- utility comparisons, and we'll -- we should be able to get that in seven days.

VICE-CHAIR GARDNER: Okay. Sounds good. Any other matter?

MR. OVERSTREET: Not for these witnesses, Your Honor.

VICE-CHAIR GARDNER: Okay. So these witnesses are free to go; is that right?

MR. KURTZ: Yes.

VICE-CHAIR GARDNER: These witnesses are free to go, so we'll just keep going.

MR. OVERSTREET: Thank you.

VICE-CHAIR GARDNER: While they are leaving, let me just make sure that there's no one here in any of the EKPC distribution co-op cases. The hearings were canceled; is that right?

(Mr. Pinney nodded head.)

VICE-CHAIR GARDNER: Okay. Just want to make sure no one is here.

And no one is here in any of the Big Rivers distribution co-op cases?

Okay. So I don't know that we start all over, I think you just call your --

MR. OVERSTREET: Next witness?

VICE-CHAIR GARDNER: -- next witness.

MR. OVERSTREET: Thank you. We would call, Your Honor, Ranie K. Wohnhas.

* * *

RANIE K. WOHNHAS, called by Kentucky Power Company, having been first duly sworn, testified as follows:

VICE-CHAIR GARDNER: Please have a seat. Please state your full name, please.

THE WITNESS: Ranie K. Wohnhas.

VICE-CHAIR GARDNER: And what is your position with the -- with Kentucky Power, please?

THE WITNESS: I'm the managing director of regulatory and finance for Kentucky Power.

VICE-CHAIR GARDNER: All right. How long have you had that position?

THE WITNESS: Since 2010.

VICE-CHAIR GARDNER: And what is your address, please?

THE WITNESS: 101-A Enterprise Drive, Frankfort, Kentucky 40602.

VICE-CHAIR GARDNER: You may ask.

DIRECT EXAMINATION

By Mr. Overstreet:

Q. Mr. Wohnhas, did you cause to be filed in

this proceeding certain responses to data requests and prefiled testimony?
A. I did.
Q. And do you have any corrections or changes to either the data request responses or the prefiled testimony?
A. I do not.
Q. And if you were asked those same questions here today, would your responses be the same?
A. They would.
MR. OVERSTREET: The witness is available.
VICE-CHAIR GARDNER: Mr. Kurtz.
MR. KURTZ: Thank you, Your Honor.

CROSS-EXAMINATION

By Mr. Kurtz:
Q. Good afternoon, Mr. Wohnhas.
A. Good afternoon.
Q. Okay. A little bit of background. January 1, 2014, ushered in a sort of a new era for Kentucky Power in that the interconnection agreement terminated at that point?
A. It did terminate at that point.
Q. Okay. Kentucky Power -- the interconnection agreement had governed the operations between Kentucky Power, Ohio Power, Indiana & Michigan,

Appalachian Power, and Columbus and Southern since the early 1950s?
A. Sometime about then, and then it had been revised that Columbus Southern and Ohio Power had merged at a point in time and it was just four members.
Q. Now, beginning January 1, 2014, Kentucky Power operates as a stand-alone utility, essentially, under the loose power pooling agreement that -- what do we call the new one? The power share?
A. P --
Q. What is the new one?
A. PSA.
Q. PSA. But in other -- but it doesn't have the same sort of tight interconnection and cost sharing of the --
A. Absolutely. It's nothing like the pool. It's not a pool arrangement.
Q. Okay. Under the old pool agreement, the deficit companies made capacity equalization payments to the surplus companies, correct?
A. That is correct.
Q. And Kentucky Power was a deficit company, so you were paying capacity equalization payments?

A. That is correct.
Q. And among other things, the payment of capacity equalization payments entitled you to -- entitled the companies to have first call on the excess generation of your affiliates at cost?
A. We were able to go to the pool, and when we were short, to be able to have power come from the pool most of the time.
Q. And one of the reasons you've identified, I think, that the fuel adjustment has gone up is because being able to buy from an affiliate at cost is no longer there; is that correct?
A. It was a piece of the puzzle in the fact that because of the pool, the pool was -- especially when the Cook Nuclear Plant was running as far as the mix from the pool, it was almost consistently cheaper than going to any market.
Q. And, of course, I&M had first call to the Cook Nuclear generation, did it not?
A. Sure.
Q. Yeah. Okay. But the capacity equalization payments are still embedded in base rates, correct?
A. Yes.
Q. Okay. Now, let's go through how the energy flowed under the old pool agreement. First of all,

Kentucky Power, like all the other operating companies, had first call to your generation to serve your native load; is that correct?
A. Would you say it again?
Q. You --
A. I'm sorry.
Q. You had first call for Big Sandy 1, Big Sandy 2, and Rockport to serve your native load first?
A. Yes.
Q. Okay. And same with the other companies, Ohio Power, I&M, they serve their native load first out of their generation?
A. That's correct.
Q. Okay. When you had or anybody had extra power, you -- the affiliates were able to buy it at cost?
A. At the average cost of the surplus, yes.
Q. Okay. And whatever power was left over after all that was sold off system?
A. Could be sold off system, yes.
Q. And each of the operating companies received its member load ratio share of profits from the total AEP pool of profits from off-system sales?
A. That's correct.
Q. Kentucky Power is about six to seven percent

member load ratio, it used to be?
A. In that range, yes.
Q. So Kentucky Power got six to seven percent of total AEP East off-system sales profits no matter whose power plant actually made the off-system sale; is that correct?
A. That is correct.
Q. Okay. The amount of profits from off-system sales that are embedded in base rates that's been discussed is 15.3 million?
A. Approximately 15.3, yes.
Q. And that 15.3 million was reflective of the member load ratio sharing of the entire AEP pool of profits from off-system sales, was it not?
A. Yes, because that -- it was established with the pool still in effect. That's correct.
Q. And, of course, that member load ratio sharing, the whole pooling structure is gone at this point?
A. It is.
Q. Thank you. Now, also beginning January 1, 2014, Kentucky Power took ownership of 50 percent of Mitchell Units 1 and 2, correct?
A. Yes.
Q. Okay. Seven hundred and eighty megawatts

total?
A. That is correct.
Q. Now, you've seen in the testimony of the KIUC witnesses that with Mitchell, and I don't think you've contested this, Kentucky Power has a projected reserve margin of 57.3 percent?
A. During the stipulation settlement agreement time frame, approximately.
Q. During the period when you owned essentially both Big Sandy and Mitchell?
A. That's correct.
Q. Because Mitchell is intended to replace Big Sandy. Big Sandy 2 is 800 megawatts, Mitchell is 780 megawatts, the idea was because Big Sandy 2 is going to retire April 1, 2005 [sic], because of MATS, you got Mitchell as a replacement?
A. Yeah. It was -- yeah, that was the whole purpose of the Mitchell transfer case.
Q. Okay. So for the -- for the 17-month period January 1, 2014, through May 31, 2015, you're going -- Kentucky Power has more power than it needs for native load. Is that a fair statement?
A. That's fair.
Q. And also during the Mitchell stipulation, Kentucky Power was authorized to retain 100 percent

of profits from off-system sales as a new stand-alone entity; is that correct?
A. One hundred percent profits above the base of 15.3 that goes to the customers.
Q. And the 15.3 million that was used to offset base rates in the last rate case was a vestment of the old pooling structure that no longer exists?
A. It was still the amount that's in base rates no matter how it was established, but yes.
Q. And capacity equalization payments are in base rates, but that -- those no longer exist either, do they?
A. That's true, and we only got 44 million of the total investment of the Mitchell plant.
Q. Now, part of the case to put Mitchell into rates, the Mitchell settlement, there was an estimate on Kentucky Power's part that there would be fuel savings from Mitchell of approximately $16.7 million per year?
A. As part of, I believe it's Paragraph 2, it was 16.75 million based on the coal costs. That would be the difference between delivered at Mitchell versus Big Sandy.
Q. Okay. Now, as we've come to learn in this case, there was a significant fuel expense

associated with Mitchell that was not factored into the earlier thinking on the Mitchell transaction. By that I'm referring to the Mitchell no-load costs. Do you -- would you say that's -- would you agree with that?

A. No-load cost was increased due to unexpected circumstances that weren't intended or discussed during settlement.

Q. Okay. The annual Mitchell no-load costs are $38.2 million; is that correct?

A. I don't know what the -- off the top of my head, I don't know what the annual -- where you're getting that number.

Q. Well, when you redid the Mitchell settlement agreement documents, Staff asked you to redo it putting the Mitchell no-load costs in where originally in the Mitchell settlement you said that the 17-month rate increase was going to be 5.33 percent --

A. Yes.

Q. -- Staff said put in Mitchell no-load and it goes to 12.81 percent rate increase?

A. Can you refer me to that data request --

Q. Yeah, that was --

A. -- please?

Q. Yeah, that was the 38.2 million.
A. I'd just like to see that, just -- I remember the context, I just don't know what data request that was.
Q. It was response to the Staff --
A. If you don't mind.
Q. Yes. Staff --
MR. RAFF: Third request, Item Number 9.
THE WITNESS: I'm sorry, sir? What was it, Richard?
MR. RAFF: Third request, Item Number 9.
THE WITNESS: Thank you.
MR. RAFF: Attachment 1, I believe.
COMMISSIONER BREATHITT: The Commission's third? Staff's third?
MR. RAFF: Yes.
COMMISSIONER BREATHITT: Okay. Will you give me a second to find it?
MR. RAFF: The second page of the group that you have there.
THE WITNESS: Mark, do you have the attachment?
MR. OVERSTREET: I do.
THE WITNESS: I, for some reason, don't have the attachment.

MR. OVERSTREET: May I approach the witness to give him the attachment?

MR. KURTZ: Your Honor, if I can approach, I have that, separate copies of that. Your Honor, if we could, could we just, for ease of reference, mark this as KIUC Number 1?

VICE-CHAIR GARDNER: Sure. The three pages?

MR. KURTZ: Yes.

A. So in answer to your question, Mr. Kurtz, yes, it was 38,252 -- 38,252,000, yes.

Q. Okay. Back to that exhibit. The -- let's see. By way of additional background, would you agree that in April of 2014, the last month of the review period, Kentucky Power sold more power off-system than on-system?

A. I don't have that information in front of me.

Q. Do you have Kentucky Power response to Staff, first set, Item Number 21, Attachment 1?

MR. KURTZ: Again, if I could approach, I have copies for ease of reference.

A. First set, number -- which number?

Q. Twenty-nine.

A. Oh, 29. I'm sorry.

VICE-CHAIR GARDNER: This is KIUC 2.

MR. KURTZ: Thank you, Your Honor.

Q. Do you see down at the --
MR. OVERSTREET: Oh.
MR. KURTZ: I'm sorry?
MR. OVERSTREET: I just -- out of an abundance of caution, there's certain numbers on here that are highlighted in yellow. I assume you did that and that's not the Company's indication that it's confidential.
MR. KURTZ: Thank you. You're right. Yes. Sorry.
MR. OVERSTREET: Okay. That's fine. I just wanted to double-check.
Q. You see in the -- well, this is -- this is by unit. Let me -- let me strike the last question and rephrase it.
Do you see in the bottom left-hand side of this percent megawatt hours allocated to native load, the last grouping in the bottom left-hand side of the paper?
A. I do.
Q. Okay. Let's just look at Mitchell, for example. Mitchell, in April of 2014, Mitchell 1, 52.58 percent went to native load; is that correct?
A. That's correct.
Q. Mitchell 2, 55.38 percent went to native

load?

A. Yes.

Q. Okay. Moving up the -- up the chart, in April of 2014, 43.51 percent of Rockport Unit 2 went to native load, correct?

A. That's correct.

Q. And 41.14 percent of Rockport Unit 1 went to native load, correct?

A. Yes.

Q. And Rockport is the lowest fuel cost unit, generally, on the Kentucky Power system, is it not?

A. On average, it's -- it would be -- it's normally lower.

Q. Okay. And Big Sandy 2, 39.5 percent went to native load, correct?

A. That's correct.

Q. And that's generally the highest cost unit of the -- of the coal units?

A. I don't know that it's necessarily the highest.

Q. All right. And then just to finish out there, 45.42 percent went to native load of Big Sandy Unit 1?

A. That's correct.

Q. Okay. Let -- by way of further background,

and I had the -- I had the monthly totals, but it's not -- I don't want to go through all the math, but the minimum -- the minimum -- the minimum segment cost of all of these units that are owned or leased by Kentucky Power, do you remember the response to the data request, what the minimum segment is?
A. Right.
Q. And it is 975 megawatts?
A. For all the units, you mean?
Q. Yes. Yes.
A. Off the top of my head, I could -- that's close.
Q. Okay.
A. I don't remember the exact number.
Q. Do you -- and you, of course, rebutted Mr. Hayet and Mr. Palmer or just Mr. Palmer?
A. Both.
Q. Both. Okay. Do you recall the testimony that -- of Mr. Hayet that for 31 percent of the hours of the year Kentucky Power's native load is less than the minimum, the system -- the minimum operating levels of all those power plants?
A. If all of them were run at the same time.
Q. Okay. Do you remember what the maximum output of the power plants are? Is?

A. For all the units?
Q. Yeah, all -- yeah, all the units.
A. All units at maximum?
Q. Yeah, during the 17-month period.
A. It's -- I think it's 16 something.
Q. No, no, not Kentucky Power native load, but the maximum of all the units.
A. All right. You have to --
Q. Two thousand --
A. Two thou -- about 2,000, yes.
Q. Two thousand two hundred and fifty megawatts? So 31 percent of the hours of the year Kentucky Power's native load is less than 975 megawatts, and -- which is the minimum of the units?
A. Again, assuming all the units are running at a particular time, which, you know, is not a -- has not happened --
Q. Okay.
A. -- all that often.
Q. Yeah. Okay. Does Kentucky Power dispatch Rockport?
A. Does Kentucky Power -- all of the dispatch comes out of Columbus, through the service corp.
Q. Kentucky -- Rock -- Kentucky Power has a 15 percent lease interest in Rockport, the plant is

actually owned by, I think, I&M and AEP Generating Company?
A. Yeah, we get a 30 percent share of AEG's 50 percent, which comes out to the 15 percent.
Q. Okay. So Kentucky Power doesn't dispatch those units, you just get your 15 percent share of whatever energy comes out of those units?
A. No. Kentucky Power itself doesn't dispatch Big Sandy or Mitchell. All that dispatch is done by our group in Columbus that dispatches on behalf of Kentucky Power, and Rockport would be part of that dispatch.
Q. Okay. Is that true with Mitchell also, did you say?
A. Yes, it is.
Q. Okay. Because the other half of Mitchell is owned by who?
A. Currently by AEP Generation Resources.
Q. That's an unregulated affiliate?
A. Currently, yes.
Q. Do you have a -- know of a definition of the minimum segment cost, the 975 megawatts, if I were to ask you to define what that means?
A. Well, if you go to -- in 29, where we were already at, we defined no-load cost, first of all,

and then the total, you know, that is that incremental of fixed cost before you create any generation. And then --

VICE-CHAIR GARDNER: Excuse me. Which -- I'm sorry. Which number?

THE WITNESS: P -- I'm sorry. Staff, first set, Number 29.

VICE-CHAIR GARDNER: And what number? What --

THE WITNESS: At the very beginning, even before a., we define no-load costs --

VICE-CHAIR GARDNER: Okay. I see. Thank you.

THE WITNESS: -- are the fixed and consumables.

A. All right. So that's the no-load cost. But then up to the minimum load, which that minimum is at the minimum level that that unit can operate continually in a safe, reliable fashion, and each unit has a different megawatt hour up to that point, but -- so between no-load cost and that minimum level, you know, are the costs of start-up to get to that level.

Q. Okay. So the minimum, the 975 megawatts total system, that's the power plants are as low as they can physically safely operate and generate electricity?

A. If all four run -- or all six units were run at one time; that is correct.

Q. And no-load fuel cost is the cost of fuel to burn, to boil water, to make steam, to turn the turbine, to turn the generator and get it synced up to the grid but produce no megawatt hours?

A. No. You know, and again, Kelly Pearce is probably a better person to -- if you want to reask that question when he's on the stand. But, you know, the no-load portion of that, all right, there's nothing generating. All right. There is zero generation going on, but it's -- as it states there in 29, you know, the fixed cost, you know, if you want to read that for everyone.

Q. Go ahead. Go ahead.

A. That's fine. "Are the fixed fuel and consumable costs incurred when a unit is in operation that are not dependent on the output level of the unit."

And we say, "In other words, these are the costs incurred in any hour to ensure that a generating unit is online and available to serve internal load, which has long been a principle of

how AEP dispatches its units."
Q. So you're --
A. So if you look on a curve, you know, there's -- again, and Kelly can readdress this, you go up a certain level and that's no-load cost, and then it has a curve up towards the minimum, where then we have the actual start-up costs that are needed to get it to and just say, example, 200 megawatts for a particular unit.
Q. So let's go back again. A no-load state you're produce -- the power plant is producing zero units of energy?
A. That is correct.
Q. Okay. So you -- so it's a theoretical statement?
A. It is. It's a cost as we have discussed in the other -- if you were here in the other cases this morning, it's a cost. It is not defined by itself, doesn't have a separate account number, but it's a part of the total fuel costs that the Company incurs.
Q. Okay. Did you call it a fixed cost earlier?
A. Yes.
Q. Okay. Now, again, it's the amount of fuel to burn to turn to make steam just up to the point

right before you make actually any electricity?
A. That would be my interpretation. You know, if Mr. Pearce has a different way we can say it, but that's -- yes.
Q. Okay. Now, no utility would ever -- first of all, you couldn't physically run a power plant like that at that level, could you?
A. No. If there's -- if it does not generate, if it's generating zero, even though there's a no-load cost cost that's calculated, nothing gets passed through to the customer. All right? So if there's zero generation, there is zero no-load cost.
Q. Well, let's start again.
A. That's a fact.
Q. Well, you can't operate a power plant at the no-load level, can you? Because the minimum you can operate it is the minimum, which is above no-load, right?
A. That's correct.
Q. Okay. So you can't physically operate just to the brink of producing electricity, it's a theoretical --
A. But that's the idea behind a theoretical is that if there's not any generation -- all right. For instance, if Big Sandy 1 for an example, is not

running, it is down, not churning a single megawatt, zero no-load cost. There is no load cost that gets allocated to any customer.

Q. No utility ever would -- even if you could physically operate at no-load, why would you burn coal to make zero?

A. You don't burn coal to make zero. It's a --

Q. Right. You would never -- you would never --

A. Again, that's what -- that's the point we're making.

Q. Right. You would never do that in the real world even if you could, because you're burning coal and getting no output?

A. Yeah, there is no burning of coal to get a no-load cost. All right? It's just fixed costs. There's nothing burning.

Q. You've calculated the no-load costs by unit, haven't you, for the Commission?

A. Yes, I think that was --

Q. Okay.

A. The answer is yes.

Q. You've called it a fixed cost. Could you -- could you make any electricity without incurring the no-load cost?

A. Ask that again, please.

Q. Could you make electricity without incurring the no-load cost?
A. No.
Q. So in order to sell power on system, you have to incur the no-load cost?
A. Yes.
Q. And in order to generate electricity, so off-system, you have to incur the no-load cost, correct?
A. If no-load cost is incurred, yes.
Q. You've testified that -- in big picture that you think that the way Kentucky Power has been doing fuel costs, the fuel adjustment is a reasonable rate?
A. It is a -- the way -- it's under the economic dispatch principles that Kentucky Power has been under for at least the last 30 years, yes.
Q. I'll get into this a little bit later, but when did the Commission Staff ever hear the phrase "no-load cost"? When was the first time?
A. I don't know.
Q. Didn't you answer a data request that said it was the June 26, 2014, informal conference was the first time no-load was ever discussed?
A. That -- you asked -- I mean, that's when we

brought it and discussed it. I can't answer if Staff knew of those costs prior to that or not.
Q. Well, if you assume Staff had never heard of it before the June 26, 2014, conference, then the fact that Kentucky Power had been doing something for 30 years, I mean, what difference would it make if it was a secret, so to speak?
A. I didn't say it was a secret.
MR. KURTZ: Your Honor, if we could have marked as KIUC 3. This is an excerpt from an exhibit from Mr. Kollen's [sic] testimony.
Q. Oh, sorry.
A. I can look it up, but if you're passing it out.
Q. And I would -- I just did this for ease of reference. This is from page 9 of his -- oh, Mr. Hayet's testimony. Page 9 of Mr. Hayet. If you want -- if you want to verify, you can turn to his testimony.
Have you seen this before?
A. Yes.
Q. Okay. Let's just go through by month. Let's just -- I don't want to go through by month. Let's just go to April, make it faster.
In April 2014, Kentucky Power's total fuel

costs were $27.83 per megawatt hour?
A. Yes, sir.
Q. Okay. And the amount that off-systems sales paid was $22.36 per megawatt hour?
A. That's what it shows, yes.
Q. Okay. And native load paid above the average cost, native load paid $34.40 per megawatt hour?
A. Yes.
Q. Is that correct?
A. That's what -- that's what it shows.
Q. Okay. And you think that it's reasonable to charge the off-system customers, looks like $12 a megawatt hour less than your own ratepayers?
A. No, I think, you know, in order to understand, you, the -- I don't think this shows the whole picture. It's factual numbers, but what you have to remember in looking at this is, you know, first of all, you know, we do economically dispatch that the highest cost goes to off-system sales, and that, you know -- and then we do it from a top-down, you know, down to the area of the minimums, as we discussed, and the minimums then down to -- get allocated to internal, because part of -- as was brought up by Mr. Kurtz, you know, during this stipulation settlement agreement, we do have

additional units able to run, and as part of Paragraph 7 of that stipulation settlement agreement, because we were only -- had agreed to recover only $44 million through the asset transfer rider, then we was also given the opportunity to mitigate some of that risk to our earnings by having off-system sales, and so in order to do that, you know, the units were ready.

Due to the unexpected event of a polar vortex in January and February, when there was increased need for electricity off-system, you know, the Company was able to make those sales, and at that time, then you have as many of the units that were available running, and so then, you know, we did not change any type of our allocations, any of our methods, any way that we did business just to make off-system sales, we did it exactly as we've always done it for the last 30 years, and due to the events of the stipulation, all the different things that were settled upon, then you end up with these results.

Q. Okay. Let me ask it again. In April of 2014, you charged your own ratepayers $12 a megawatt hour more for fuel than your out-of-state sales or off-system sales. You charged your native load customers 50 percent more for fuel than off-system. Just inherently you think that's fair? You think that's --

A. I think it's fair in the context that in the whole scheme of the Company was only receiving 40 percent of the value of Mitchell through base rates, and so the customers were getting the benefit of those costs, and so then when you net everything, it is definitely a ben -- a net benefit to the customer.

Q. Now, there's a funny -- there's a funny relationship, because you treat all these no-load costs as fixed costs and they go to native load no matter what, correct? No matter what volume of sales, native load always pays the no-load costs?

A. In general, yes, unless it is -- the only no-load cost that would ever be signed off is if your internal load was less than the sum of if you had all the units running. So in other words, as you have said, the 975. If for any reason that my internal load was only 900, all right, that incremental difference between 900 and 90 -- 975, a portion of that then would get allocated to off-system sales.

Q. Now, you don't mean no-load costs, you mean minimum segment, because no-load costs go to native load 100 percent of the time no matter what; isn't that correct? Should I ask Mr. Pearce that question?

A. Yeah, if you can ask Mr. Pearce.

Q. Okay.

A. I believe it's -- he can clarify that.

Q. Okay. Now, by treating no-load costs as a fixed cost, don't you have this sort of cruel irony that as native load sales go down, the fuel adjustment rate goes up, all else equal, because you're amortizing the fixed no-load costs over fewer megawatt hours?

A. You know, if you look at fuel costs in isolation, yes, but that's not the way that this needs to be looked at. It's -- that's why we settled on the various parts of the settle -- the stipulation and settlement agreement and looked at it in total.

MR. KURTZ: Your Honor, if we could have marked as KIUC 4.

VICE-CHAIR GARDNER: So ordered.

Q. You've seen this data response from Kentucky Power, have you not?

A. I have.

Q. Okay. Let's just go over the no -- these are the no-load costs by month by power plant?
A. Yes.
Q. Okay. And Staff requested this in its first set, Item 29?
A. That's correct.
Q. Okay. Now, we saw earlier -- again, I just want to focus on April 2014 -- that in April 2014, this is KIUC Number 2, this document here, that native load customers got 39.5 percent of the Big Sandy 2 generation; is that correct?
A. I'm not sure where you're at.
Q. Okay. KIUC 2. I'm sorry. I'm bouncing you back. This -- in April native load got 39.5 percent of Big Sandy 2's generation; is that correct?
A. KIUC Number 2?
Q. Yes. It's the Staff 29, this document.
A. I've already lost it. And what number again? I'm sorry.
Q. April '14, Big Sandy Unit 2 native load received 39.5 percent of the output of Big Sandy 2?
A. Yes.
Q. Now, if you look on KIUC 4 at the bottom, Big Sandy 2 in April, what was the no-load cost?
A. Big Sandy 2?

Q. Yes.
A. 4,250,145.
Q. Okay. And in that month native load paid all that no-load cost, correct? Because you treat it as a fixed cost?
A. Yes.
Q. Okay. Now, what if native load had only received one megawatt hour out of Big Sandy 2? Native load would have still got charged that same $4.2 million, correct?
A. In theory. You are not going to generate one megawatt hour, but yes.
Q. Now, for the whole month of -- month of April, Kentucky Power had $7,844,000 of no-load costs --
A. That's correct.
Q. -- is that correct?
A. That's correct.
Q. Now, this is going to be an extreme example, I know it couldn't happen, but let me -- just to demonstrate a point, if in the month of April you had one customer left on the system and she bought one megawatt hour of power from Kentucky Power and everything else was sold off-system, wouldn't that one customer be charged $7.844 million of no-load

costs?
A. I don't know if you could make that calculation. I think you're right, that's a stretch. I don't know you can make that assumption.
Q. But that -- that's the way it works.
A. Ah.
Q. So the no-load cost goes to native load regardless of the level of native load sales?
A. But you wouldn't -- you know, that's -- that's just a completely unacceptable hypothesis.
Q. Well, it's an extreme example, I know, and I said that, but it just -- but the point is that no-load goes with native load no matter how much power you sell to native load versus off-system?
A. You know, we stated, you know, time and again that, you know, we followed the economic dispatch principles, we follow our economic on how these costs are allocated and have been allocated, and, you know, it's a principle that is not -- we're not the only utility in the state that does this. There are differences on how they allocate, but we're clearly not the only one that allocates this way, and it's a very, you know, credible way of allocating the costs.
Q. Okay. Now, during the time when AE -- when

Kentucky Power was operating under the AEP pooling agreement, there was actually language in the interconnection agreement, the pooling agreement, that Mr. Pearce cited that seemed to indicate this is -- that that is the way you were supposed to do it, the treatment of no-load costs. Do you recall that?

A. Well, you can ask Mr. Pearce. I mean, I know he has a quote in there from the AEP pool agreement. It's probably better asked of Mr. Pearce.

Q. But beginning January 1, 2014, there is no more pool agreement to give guidance?

A. There is no -- there's no longer a pool agreement.

Q. Would you agree that the Commission's job, among other things, to balance interests and so forth, is to establish just and reasonable fuel rates for consumers?

A. That's part of the fuel adjustment clause is to look at the costs that have been incurred and to make sure that those costs are prudently -- that were prudently incurred and properly passed through the fuel adjustment clause.

Q. Do you -- do you know how the Commission, I'm sure you do, treats fixed environmental costs for

purposes of the environmental surcharge in terms of allocations of off-system -- to off-system sales?
A. I am.
Q. And doesn't the Commission allocate a portion of the fixed environmental costs to off-system sales?
A. They do allocate a portion of that which is, you know, basically shifting how the Company recovers those environmental costs, a shift from collecting it from the retail through the environmental through collection through off-system sales by increasing the cost of off-system sales.
Q. Now, Mr. Kollen had a long discussion about the history of that and how Kentucky Power challenged that and went up to the circuit court and the Commission was affirmed. You didn't file any rebuttal to any of that, did you?
A. No. We did not file any -- I did not file any rebuttal to that, but when you think about -- it's the same thing that's been discussed, you know, previously, that if you make a change -- and take, for instance, if you're going to change the allocation method of how these fuel costs are allocated, that it must match up with a base rate type of case in order that you don't have tracked

costs.

"Tracked costs" meaning costs that, as I said, in base rates is set up under certain parameters that -- you know, the 15.3 was based on this is how the allocation process worked. If you change that outside of a base rate case, then you are going to end up with costs aren't going to be fully recovered, in other words, tracked costs.

Q. Now, didn't we establish earlier that the 15.3 million in off-system sales profits baked into the current base rates was a vestige of the old pooling agreement, the member load ratio sharing of all of AEP's profits from off-system sales?

A. But it doesn't matter how it's developed, it's what's being collected through base rates at $15.3 million.

Q. And the -- we have to assume for ratemaking purposes the base rate is fair, just, and reasonable until the Commission rules otherwise?

A. They ruled at that case that it was fair, just, and reasonable in that case.

Q. Do you -- have you ever been involved in a situation where the Commission has disallowed fuel costs in an FAC proceed?

A. I have not, no.

Q. Are you aware that in -- do you remember in the late '90s when KU and LG&E were charging native load customers the fuel costs associated with line losses from off-system sales and the Commission said, "No, refund that money"?
A. I do not.
Q. You don't?
A. I'm sorry.
Q. Do you remember the Big Rivers fuel disallowances from the mid '90s?
A. I do not.
Q. Are you aware of any fuel case where the Commission said, "We find that fuel rate to be unreasonable, but we're not going to deal with it until the next rate case"?
A. We've never had a case -- that I'm aware of, there's never been a case at Kentucky Power where they've disallowed any fuel cost.
Q. I'm not asking for a legal opinion, but you recognize that the fuel adjustment regulation is a stand-alone regulation that requires the fuel rate to be reasonable?
A. I do, but also understand that the effect on fuel, if you change an allocation between internal and off-system sales, that it has an effect on your

off-system sales and the way it was established in base rates which then again leads to a mismatch which, you know, is the whole point here. In order to keep everything on fair and equitable, they must be matched up with a base rate case.

Q. Let me ask you to turn to your testimony, page 6.

A. I'm there.

Q. Do you have that?

A. Yes, sir.

Q. Now, on line 8 you have a number $9.884 million; is that correct?

A. That is correct.

Q. And that's quantified on your Exhibit 1, it's the cost difference between the high- and low-sulfur cools used -- coals used at Mitchell and the low-sulfur coal used at Big Sandy?

A. That's correct. It's looking and saying that the Big Sandy, if you priced it all out at the Mitchell, what the amount would be, yes.

Q. Okay. So tell me how -- tell me how you did that calculation.

A. Basically we looked at -- if you go over to my exhibit, RKW-1, and the -- and we show there the Mitchell, you have -- I wish I put column head -- or numbers on them. I apologize for that.

But you have the fourth column over says Total Actual Monthly Fuel Cost. That's all in Rockport, Big Sandy, and Mitchell. And what the difference is in the next column over is basically taking that instead of the Mitchell units at -- I'm sorry. I'm sorry. That the Big Sandy units, we would price them out at Mitchell's cost.

Q. Okay. And --

A. And so you have those differences shown out there in the last few columns.

Q. Okay. You took the Big Sandy generation and said if it were to have the same fuel cost as Mitchell, this would be the savings?

A. That -- that's correct.

Q. Okay.

A. Which is -- which is similar to what we did in Paragraph 7 in coming up with -- we made an estimated $2.50 per megawatt hour difference to the estimated number of tons would come up with that 16.75 million. This is trying to emulate that, Mr. Kurtz.

Q. Now, you recognize that not all the Big Sandy megawatt hours go to native load, correct?

A. Yes.

Q. Okay. And, in fact, from KIUC 2 we saw that in April, for example, only 39.5 percent of Big Sandy 2 megawatt hours went to native load, right?
A. But back to Paragraph 2, in the stipulation, you know, that quick analysis to come up with that number, you know, was not changing that difference of Big Sandy between internal and off-system loads either.
Q. I want to go to your Exhibit 1, this 9.88 million.
A. Yes, sir.
Q. You swapped out the fuel costs of Big Sandy and Mitchell, and you say, "Well, Big Sandy has a higher fuel cost than Mitchell, therefore ratepayers are saved 9.88 million," but the thing I want to discuss is ratepayers aren't getting all the generation from Big Sandy, we're only getting 40 percent of it in the April month, so how is this calculation accurate?
A. The calculation is accurate only in the context against the 16.75 million. That's the only purpose of this calculation.
Q. And this also doesn't show the $38.2 million of no-load costs that consumers are paying with respect to Mitchell?

A. Yes. This was only to look at in comparison to Paragraph 2 of the stipulation agreement.

Q. The -- now, at the time of the Mitchell settlement, Kentucky Power and AEPSC employees were not aware of the magnitude of the no-load costs of Mitchell; is that correct? I'll ask you --

A. We -- what we -- at the time of the settlement stipulation agreement, we did not see an impact based on the fact that we assumed, as I think is proper, a normal type of situation and that, you know, Big Sand -- Mitchell would be used more than Big Sandy for internal because of the cheaper cost, and that even though we had an opportunity to maybe make some off-system sales, there was no guarantee, so the allocation principles that had always been there, you know, we didn't anticipate having to make any changes and we did not make any changes to those principles.

Q. Well, let me just hand out as KIUC, I think 5?

VICE-CHAIR GARDNER: Five.

Q. Staff asked you some questions about what you knew about the no-load and when you knew it.

A. Uh-huh.

Q. Do you recognize this data response?

A. I do.

Q. Okay. Staff asked, "Given that Kentucky Power allocates 100 percent of 'no load costs' to native load customers, state whether Kentucky Power or American Electric Power Company employees were aware of the magnitude that the Mitchell 'no load costs' would have on Kentucky Power's internal customers prior to the July 2, 2013 filing of the Stipulation and Settlement Agreement in" the Mitchell case.

And your answer was -- can you read your answer? At least the first sentence. Read it all if you want, but --

A. "No. Kentucky Power and AEPSC employees were not aware of the magnitude of the post-December 31, 2013 no load costs or their effect on the Company's internal customers."

Q. When did you become aware of the magnitude?

A. We became aware of the magnitude probably towards the end of February, March, and the fact that my staff, as they starting seeing the fuel costs, saw that there was an increase, and we started to ask questions internally to our own internal investigation through our discussions with Columbus. And that occurred over the next two to three months in trying to understand why everything, you know, was changing.

So that was the beginning of it, and, you know, come towards the end of April, early May, after seeing -- again, remember that we're on the two-month lag, so, you know, January's costs, actuals we don't get until -- till late February, and so as you look at a couple months, part of what we were doing as well -- we knew that with Mitchell coming in and the pool going out, when you have changes to your systems, you want to make sure that everything is operating properly, and so, you know, we were going through our due diligence to look at all these costs, to investigate and, you know, ask ourselves did we change something in there, did something happen that we wouldn't -- that, you know, was incorrect.

Through all of that due diligence, and it took a while to see a few months that -- how this was incurring, did we see the results and attribute that a great portion of these changes was due to the no-load costs.

Q. Why did you wait until June 26th to even disclose the existence of the significant cost to Staff?

A. It wasn't that late. There was conversations between our staff and the Commission Staff on issues that we were going to bring up as we were talking to them about changes during the year, and that was one of the issues that was asked of us was, you know, as -- are we -- are we aware of the increase in the fuel, and we said yes, and we said that as soon as we understand and what that is, you know, we will let you know.

And so then towards the end of April, May, when we were aware of it, we set up the informal conference. It just -- the conference just didn't happen till June 26th. But there were conversations between us and Staff.

MR. KURTZ: Okay. Let's -- KIUC 6, if we could.

VICE-CHAIR GARDNER: Gesundheit.

THE WITNESS: Thank you.

Q. Do you recognize this data request?

A. I do.

Q. Okay. Let's just -- let -- I'll ask you about g. first. Staff said, "State whether 'no load costs' are discussed in Kentucky Power's Cost Allocation Manual. If yes, provide excerpts."

What was the answer?

A. "'No load costs' are not addressed within the

Cost Allocation Manual."
Q. Okay. And then Staff asked you on j., "State whether Kentucky Power has discussed 'no load costs' with the Commission prior to the meeting held on June 26, 2014, at the Commission's offices. If yes, identify the proceeding."
Can you read your answer?
A. "Kentucky Power is not aware of any proceeding in which inquiry has been made recording 'no load costs.'"
Q. Does that mean Staff first learned of the no-load costs on June 26, 2014?
A. It means that Kentucky Power was not aware. If that was the first time -- it may have been the first time. I cannot definitively answer if it was Staff's. All I know is that we were not able to find any proceeding where it was discussed.
MR. KURTZ: Going to mark this KIUC 7.
Q. Do you recognize this document, Mr. Wohnhas? That's our -- that's our handwriting, my handwriting or somebody's, June 26.
A. This is the document that was handed out during the informal conference held on June 26.
Q. Okay. I just want to breeze through it. There's quite a bit of detail on weighted average

costs of coal and coal pile adjustments and the illustration of coal surveys and this type of thing.

A. Yes.

Q. Is that -- is that fair?

A. Yes.

Q. Okay. A lot of information on forced outage calculation, page 16. Page 17 there's -- there are detailed documentation. Do you -- let's see. Can you turn to page 22?

A. Yes, sir.

Q. The second bullet point, (Reading) Kentucky Power's methodology for allocating no-load costs to internal load has not changed.

Is that the only discussion of no-load costs in your presentation?

A. No. If you recall, we had a very extended verbal discussion of this for probably 45 minutes.

Q. Yeah, I do remember, but I mean in the presentation, your written presentation, is that the only discussion of no-load costs?

A. That was the only -- as a bullet to -- to have that discussed, yes.

Q. That's a fairly brief -- a brief discussion of a $38 million per year cost, is it not?

A. It wasn't a discussion, it was just a bullet point to make -- to allow us to remember to have this discussion during the formal conference.

Q. So the -- at least the written materials, it's not a very in-depth discussion, would you agree?

A. It's not a discussion at all.

Q. Okay. But you did have a very detailed -- 20 pages on inventory, on all these other things here; is that correct?

A. There's other different layouts, yes.

Q. The very last page is entitled Increase in Fuel Adjustment Clause, Contributing Factors, Termination of the AEP East System Pool; is that correct?

A. Yes.

Q. Okay. And then the last bullet is Inclusion of Mitchell in Kentucky Power's Portfolio?

A. Yes.

Q. Okay. That came as sort of a surprise, because when the Commission approved the Mitchell settlement, the Commission was told and intervenors and signatories were told this was going to be a $16.75 million fuel savings, correct?

A. You know, as I said before, you know, we did not anticipate the idea of no-load costs having an increase due to this happening. It was not until the events of January through the cold polar vortex did, you know, it come about that now these units were going to running all at the same time.

So, you know, once those events happened, you know, things changed on how -- we did not expect those, you know, when we were discussing the stipulation settlement agreement.

Q. You mentioned polar vortex a couple times. On page 6 of your testimony, line 16, you say, "More fundamentally, the higher no load costs are driven principally by the fact that the extreme cold weather experienced during the January and February 2014 Polar Vortex created a seldom-seen and never-contemplated demand for the Company's generation."

Did I read that correctly?

A. You did.

Q. Okay. Can you turn back to KIUC Exhibit 4, the no-load costs by unit by month?

A. Yes, sir.

Q. Okay. The -- let's look at your no-load costs total system for January 2014. 9.5 million; is that correct?

A. That is correct.

Q. Okay. February, the other polar vortex month you cite, 7.5 million, correct?
A. That's correct.
Q. Okay. And then in March it's 6.7 million, correct?
A. Yes.
Q. And then in April it's higher than it was in February, it's 7.8 million.
A. That's correct.
Q. So why do you testify that the higher no-load costs are driven principally by the February and January polar vortex when your April no-load costs were higher than February?
A. Well, without looking at all of the things that happened, as, again, part of the stipulation settlement agreement was the fact of Paragraph 7 where we had the opportunity to have off-system sales, and if there were opportunities in April that may not have been there in March, we would have ran those units to take advantage of that opportunity.
Q. No, but you're blaming the high no-load costs on the polar vortex, and the polar vortex didn't have anything to do with it in April, and it's higher than it was in February.
A. That's -- the cold weather clearly in January

and February, you know, drove the running of all the units to take care of not only our increased internal load, but then also the opportunity for off-system sales after we took care of our internal load.

And again, in following months you're still going to have the opportunity, whether it's completely due to the polar vertex -- I'm sorry, vortex, the cold weather, or the opportunity sales based on situations that are out there in the market to make those sales.

Q. How can you blame the high no-load costs on the polar vortex when April was higher than February?

A. I don't know how to explain it differently to you, sir.

Q. Okay. You have -- when Staff asked you to redo the Mitchell settlement spreadsheet -- is that KIUC 1? Okay. Do you have KIUC 1 in front of you? Do you have KIUC 1 in front of you?

A. Yes.

Q. Okay. Let me hand you another exhibit. It's the original Staff data request.

MR. KURTZ: If we could have it marked as KIUC 8.

Q. Do you recognize this document from the Mitchell case?
A. I do.
Q. Okay. This is -- you're -- the Staff -- do you read the -- well, the request at the top says, (Reading) Provide an exhibit, with electronic copy, all formats [sic] attached, et cetera.
"The schedule should reflect all known and measurable adjustments and at a minimum should reflect," and the Staff gave you a lot of different things.
A. Yes, sir.
Q. Can you -- can you turn to the last page of this?
A. To Attachment 1?
Q. Yes.
A. Yes.
Q. Okay. Column one was the rate, the projected rate increase if you were going to go ahead and build a scrubber at Big Sandy 2 at 25.59 percent, correct?
A. That is correct.
Q. Okay. And what the Company told the Commission was, for the 17-month period where Kentucky Power would own both Mitchell and Big

Sandy, the rate increase on consumers was only projected to be 5.33 percent, correct?
A. Yes, sir.
Q. Now, that was kind of, at least I thought, a small price to pay to retire one unit, get a whole nother unit. It seems that was relatively modest. Was that the way you understood that number to be interpreted?
A. Well, it was, you know, a good deal to get the Mitchell unit, but the Kentump -- the Kentuck -- the Company was only getting 44 million of the -- or roughly 40 percent of the total value of that investment, at least for the next 17, 18 months.
Q. Okay. But now when Staff in KIUC 1 said redo that exhibit but add the Mitchell no-load costs, you see that same exhibit with a $38,252,000 no-load cost right in the middle?
A. I do. But I also notice that in 5-10, in the question that you -- that you read a few minutes ago, it says, "The schedule should reflect all known and measurable adjustments." And we reflected all known and measurable adjustments. There was nothing around no-load costs that we saw was changing at the time 5 -10 was developed.
Q. Well, how could you forget about a

$38 million cost?
A. There wasn't a $38 million cost in July -- when we look at -- and assuming normal weather, normal occurrences, that wouldn't have happened. We did not have it forecasted, so it's not something that you -- in hindsight it all looks good, but at the time you were there, these costs we did not expect to change.
Q. Well, let's go back a little bit. Staff never even heard the phrase no-load, as far as I can tell from the paper trail, until June of 2014, and you were not able to find out -- cite anyplace where they were informed about that, correct?
A. That's correct.
Q. Okay. So when -- and all the Mitchell no-load costs go on native load customers no matter how much Mitchell serves native load, correct?
A. Correct.
Q. It's a fixed cost, as you've described it, a fixed fuel cost.
A. But if the units were to run similar and if there would not have been a polar vortex, if 2013 -- I'm sorry, 2014's winter weather pattern had been very similar to 2013, you would not have -- you would not have incurred all these additional no-load

costs, and thus you would not have this increase in fuel.

Q. Is that the polar vortex from April?

A. That's the increase -- we could have had -- increased in some no-load costs due to Paragraph 7, but it would not have been, you know, due to the extra needed for covering the polar vortex.

Q. Now, when Staff asked you to put the no-load costs in here, in your Mitchell analysis, the rate increase goes from 5.33 percent to 12.81 percent, correct?

A. That is correct.

Q. That's 140 percent higher number than what the Commission and, well, the signatory parties were led to believe.

A. Well, but you failed to go to the next column where the total impact was going to be 13.98, and then it jumps only to 15.01 percent. So there's a bigger difference in the interim, but the total rate impact is, you know, basically only one percent difference for the whole Mitchell as a whole.

Q. Yeah, yeah, I'm going to foc -- well, still 15 percent is higher than 14 percent.

A. It is.

Q. But that's nominal. I think anyone can excuse, but being off by 140 percent and forgetting a $38 million cost, that's --

A. We didn't forget a cost.

Q. Well --

A. All right? You know, I don't -- I don't know how to make it any clearer that those costs were not anticipated to change, and you can't make an estimate of something you don't think is going to change. It was not known and measurable at the time we were discussing the stipulation and settlement agreement.

Q. Somebody in AEP knew how no-load costs were handled for fuel adjustment purposes. You've been doing it the same way for 30 years.

A. Sure.

Q. So why wasn't that person brought in to bear on the known and measurable changes?

A. But again, we didn't see anything changing. We did not see the load changing, so there was no anticipated change to no-load costs.

Q. I want to just hand you one final exhibit, Mr. Wohnhas, KIUC 9.

A. Thank you.

Q. Do you recognize this from Mr. Hayet's testimony, page 15 -- 13? Page 15, do you recognize

this -- this document or this exhibit?
A. I do.
Q. Okay. Now, what he did is he looked at the -- on the left on the top, the Kentucky Power, this is how you allocated fuel costs between native load and off-system sales for each of the power plants over the four-month period. Is that the way you understood it when you reviewed his testimony?
A. Sure.
Q. Okay. So off-system sales out of Big Sandy for the four-month period paid $25.81 a megawatt hour and native load was $35.25?
A. Yes.
Q. So native load paid $9.44 more than off-system for the Big Sandy power; is that correct?
A. Yes.
Q. Okay. And for the four-month period out of Mitchell, native load customers paid $9.58 a megawatt hour more than off-system sales, correct?
A. You say 9.58?
Q. Yes.
A. Yes.
Q. Okay. And Rockport again, native load paid $3.07 a megawatt hour more than off-system, correct?
A. Yes.

Q. Now, he said, well, what would it have been if you did the East Kentucky stacking? And there you get pretty close. Native load and off-system aren't that far apart. For Big Sandy off-system pays $.97 a megawatt hour more than native load, but just a little bit more, right? That's what it shows?

A. For this calculation.

Q. And that for Mitchell native load would pay a little bit less, well, $4.06, little bit less, but off-system isn't that far off the market, it's $4 higher, correct?

A. Yes.

Q. And then for Rockport, again, pretty similar, native load only pays $1.04 a megawatt hour less than off-system, but still just a little bit less.

A. Yes.

Q. So it's not as -- nearly as dramatic of a swing in the different fuel costs for the different jurisdictions versus your method. That part is true.

A. I mean, it's just -- it's a complete different allocation method and that's the numbers that come out. You have to realize that if you make this allocation change and you shift, as a short term, you may take a short-term benefit on your fuel costs, but you make a long-term detriment to your off-system sales. And, you know, getting out of the stipulation settlement agreement 100 percent, going to Kentucky Power and you go back to a 60/40 sharing, you've hurt both the Company and the customer's ability to share in off-system sales, 'cause the dispatch costs go up for the units due to the off -- the additional cost to off-system sales, so that opportunity is now much less.

Q. Now, during the four months, January through April, would you agree that Kentucky Power made profits from off-system sales of $49,635,000?

A. Where are you getting that number?

Q. It's from the Kollen chart where's he's got the big spike in the off-system sales profits and he's got the numbers. It's also an exhibit to his testimony.

A. Is it an exhibit or a table?

Q. It's both. But go to his Exhibit -- I think 3 or 5. Oh. How about 7? Yeah. Kollen Exhibit 7. It's got profits from off-system sales, January '14 -- these are right off your fuel schedule -- 18.397 million, February 11 --

A. Eleven, yes.

Q. Okay.
A. Okay.
Q. So puts -- during the four-month period, Kentucky Power made profits from off-system sales of 49,635,000; is that correct?
A. Yes.
Q. Now, if the Commission were to adopt the KIUC/Attorney General recommendation, your profits from off-systems sales would go down by 12.648 million? Well, plus interest.
A. That's the calculation you made, yes.
Q. You would still -- excluding the interest for the time being, you would still have $37 million in profits from off-system sales in the first four months of the year, even if the Attorney General/KIUC recommendation was adopted?
A. That's correct. But I would still only be getting $44 million of the base investment in the Mitchell plant, and thus, you know -- and it would be going against the principles of the settlement agreement in Paragraph 7 with the opportunity.
So we're changing the way that the stipulation works for the benefit of not -- for an event, being the polar vortex and such, that no one was aware of.

Q. So if your profit margin from off-system sales in four months goes down from 49.6 million to 37 million, that's still a lot of money, isn't it?
A. In comparison to what? I mean, it's a lot of money, yes.
MR. KURTZ: Okay. Your Honor, those are all my questions for now.
VICE-CHAIR GARDNER: Mr. Cook.

CROSS-EXAMINATION

By Mr. Cook:
Q. Just a couple of quick questions, Mr. Wohnhas. The Attorney General was not a party to the settlement and stipulation in the 2012-578 case; is that correct?
A. That is correct.
Q. And currently the Attorney General has that stipulation on appeal. Is that your understanding too?
A. That's correct.
MR. COOK: That's all.
VICE-CHAIR GARDNER: Okay. Thank you.

CROSS-EXAMINATION

By Mr. Raff:
Q. Good afternoon, Mr. Wohnhas.
A. Good afternoon, sir.

Q. I just have a couple of questions. In the four months of January through April 2014, did Kentucky Power allocate to native load customers any no-load fuel costs for Big Sandy Unit 2 for any hour that native load could have been met without power from Big Sandy 2?
A. I don't know the actuals of that, we'd have to ask Mr. Pearce, but in theory, no, all the costs would have been allocated to native load customers. Based on what we just discussed, if the units are running and --
Q. Well --
A. -- whether it's Big Sandy 1, 2, Mitchell, and to cover -- and if, for instance, you know, to cover the load, all the no-load costs would be assigned to the internal load, to the internal customers.
Q. So your answer is yes. My question was: For the four months of January through April, did Kentucky Power allocate to native load customers any no-load fuel costs for Big Sandy 2 for --
A. I'm sorry. But you're -- you're correct. It is yes.
Q. -- hours --
A. I'm sorry. I thought did not.
Q. Okay.

A. But yes.
Q. All right.
A. The answer is yes.
Q. It did. Okay.
A. I apologize.
Q. All right. Thank you. Mr. Kurtz asked you if you thought it was fair for native load customers to be charged fuel costs that were 50 percent higher than the fuel costs charged to off-system sales, and your response was yes because of the context whereby Kentucky Power is only being able to recover 44 million of the cost of Mitchell Units 1 and 2? Is that a fair representation of what your response was?
A. I don't think so. And if -- let me try to fully explain. If that's -- the fact that the -- due to the -- all the parameters, all the paragraphs in the stipulation and settlement agreement, you know, from the -- from the additional opportunity for off-system sales to only $44 million through the ATR, right, when you take all the aspects of what was happening and the idea of the additional load, the Company did not change any part of their processes in the allocation of load.
We allocated no-load costs up to minimum to

internal load, native load customers before January 1st, 2014. We did that prior to joining PJM. All right. We did not change anything in relationship to that.

So when you then make the calculations as they -- as they fall out, having additional load, having the idea of all the units running and not changing the methodology, the idea that the calculation shows higher -- higher fuel costs to the internal load, all right, it is fair and reasonable based on everything that happened in the settlement and stipulation agreement. Does that help?

Q. Well, let me ask this: If Kentucky Power had been recovering 100 percent of the cost of Mitchell, the two Mitchell units, for January through April of 2014, do you still think it would have been fair for your native load customers to have paid all of the no-load costs for Mitchell and Big Sandy, and the result being native load customers paying for fuel costs almost 50 percent higher than what is charged to off-system sale customers?

A. Well, in that assumption, you know, we would not, I'm sure, have been given the opportunity 100 percent of the sales margins above the $15.3 million, because we would have recovered all of Mitchell through base rates.

And, however, during that interim time, again, not anticipating, but, you know, if we would have had the polar vortex, there still would have been an increase in the no-load costs unanticipated, you know, because we would have -- assuming we would have still had Mitchell and Big Sandy for that 17-month period, even though all of it was in base rates, you know, there still would have been an increase in costs, fuel costs, that would have went to the native load customers, because that was the principle by which we've always allocated and we weren't changing that principle.

Q. So your answer is yes, even if you were recovering 100 percent of the Mitchell costs in base rates, it would still be fair to charge your native load customers significantly higher fuel costs than what would be charged to off-system sales.

A. It would definitely be reasonable based upon the past practice and not changing to -- in any way what we had done in previous; yes, sir.

Q. Okay. Is there a reason why you believe it's appropriate to charge native load customers for the no-load fuel costs during those hours where Big Sandy 2 is not needed for native load, other than the fact that that's how you've been doing it for 20 years?

A. Well, and I think Mr. Pearce will be better to give you, you know, the details of what happens when we bid in the units. You know, when we bid in the units each day -- or the day-ahead, I'm sorry, for the day-ahead, you know, we bid the units in, PJM decides whether they are accepted or not depending on the load, and we've heard that discussions earlier today, and the price. And then once they are bid in, we still do the economic dispatch of the highest -- the highest cost goes to off-system sales, whether that is Big Sandy, whether that is Mitchell, whether that is Rockport, that gets still assigned to the highest load -- the highest cost gets assigned to the off-system sales and it works its way down.

And a unit is not assigned in any particular day just to off-system sales or internal. It's bid in, and then we start the top-down approach, if it's accepted, down.

So to say that, well, you know, Big Sandy, you know, it -- it's -- again, it's not bid in just for off-system sales.

Q. All right. Well, are you saying that if the no-load costs were charged to off-system sales, that the sales would have been made at a loss rather than at a profit?

A. No, I don't -- I'm not saying that at all from a -- you know, again, it's how we develop, you know, the cost for the economic dispatch. If you're going to assign more cost to off-system sales, all right, that changes how -- the cost that's bid in, and, you know, you take the risk of that not being accepted, not being available, depending on load, for even off-system sales or it reduces the margins that you have, and under a 60/40 split, forgetting the stipulation settlement, you know, 60 percent of those profits go back to the customer, and so -- and 40 to the -- to the Company.

And so you lose, you know, some of that, and it is a benefit to both the Company and the customer, and you lose some of that.

Q. But the customer is paying 100 percent of the no-load and the Company isn't paying any, correct?

A. I'm sorry, I couldn't hear the rest of that.

Q. The customer is paying 100 percent of the no-load and the Company is paying none, correct, for the off-system sales?

A. The customer is assigned 100 percent of the

no-load. I keep -- I don't -- I'm missing the last part of your comment, sir.
Q. Well, you referred to the 60/40 split --
A. Yes, sir.
Q. -- and the fact that by being able to increase sales, it was a benefit to both the customer and the Company --
A. Yes.
Q. -- by being able to make more sales, but with respect to those sales, the 100 percent of the no-load costs are paid for by the customer --
A. By the internal customer.
Q. -- and none of those are paid for by the Company, correct?
A. That is correct.
Q. It didn't -- it doesn't come out of the Company's 60 percent share of the off-system sales, correct?
A. In the way it's established, in the way it's set up now, that is correct. Yes, sir.
Q. I seem to have lost my way here.
MR. PINNEY: What are you looking for?
MR. RAFF: I'm looking for the question.
Q. Could you please refer to page 7 and 8 of your rebuttal testimony?

A. I'm there, sir.

Q. Beginning at the bottom of -- if I can find it. Beginning at the bottom of page 7, could you read, starting at line 22, over through just the end of that sentence?

A. Yes, sir. (Reading) Paragraph 1 of the Stipulation and Settlement Agreement only provided the Company with a partial recoveny -- I'm sorry, partial recovery, then in parens, 44 million annually or approximately 40 percent, end parens, of the estimated costs associated with Kentucky Power's 50 percent undivided interest in the Mitchell generation -- generating station.

Q. Okay. Would you also refer to Kentucky Power's response to the Commission Staff's third request for information, Item 9, Attachment 1, page 1? The top of the last column shows that the cost of the service impact for the Mitchell transaction after retirement of Big Sandy 2 was 81.244 million; is that correct?

THE WITNESS: Mark, I still don't have that copy. I'm sorry.

MR. GISH: It's KIUC Number 8.

THE WITNESS: Okay. Hold on.

A. And what was the number you were asking me to

look at?
Q. Oh, then -- yes. 81.244 million.
A. Yes. 81.244 million. Yes, sir.
Q. Would you be able to provide a schedule for each month of 2014 through the most current month that data is available which shows by month the 60 percent portion of off-system sales margins that customers would have received under the 60/40 split but for the settlement agreement and the fact that the Company is retaining that 60 percent, and showing separately the bill credits that Kentucky retail customers would have received under the environmental surcharge if the surcharge had not been reset to zero in the Mitchell settlement agreement, and the amount associated with the asset transfer rider that retail ratepayers are currently paying for the Mitchell Units 1 and 2?
A. Let me summarize, if I could, just to make sure I understood what you're asking for, is that starting with January, to provide a calculation of what the -- starting with what you said the off-system sales tracker would have been with a 60/40 split as --
Q. Yes.
A. Okay. And then a calculation of the

environmental surcharge, what it actually would have been not being -- had we not been to zero --
Q. Zero.
A. -- which I think is actually filed each month as a number, but we can provide it as part of this. And then I wasn't sure I understood the last.
Q. The monthly amount that is recovered through the asset transfer rider.
A. The ATR? Yes.
Q. Yes.
A. So you want that from January through the most recent --
Q. Whatever the most recent month available, yes.
A. We can do that.
Q. Thank you. All right. Also in your rebuttal testimony at page 11, beginning at line 6.
A. Yes, sir.
Q. Could you read that paragraph, please?
A. Yes, sir. (Reading) If Mr. Kollen's no-load cost allocation method were used, the Company's test year off-system sales margin would have been lower. As a result of the OSS margin credit against base rates -- I'm sorry. As a result, the OSS margin credit against base rates would have been lower.

The lower OSS margin credit would have required the amount recoverable through base rates to increase for the Company to meet its Commission-approved revenue requirement. Because they are interrelated methods for the Company to meet its Commission-approved revenue requirement, any decrease in the OSS margin credited against base rates must be balanced by a corresponding increase in the amount of recoverable through base rates. Mr. Kollen's approach ignores this fundamental concept and must therefore be rejected.

Q. What you're referring to in this paragraph is how revenue requirements are determined in a base rate case; is that correct?
A. That is correct, sir.
Q. Okay. And in Kentucky Power's last base rate case, a 60/40 sharing for off-system sales margin was established, correct?
A. That is correct.
Q. And that 60/40 sharing is no longer in effect temporarily?
A. Temporarily; that is correct.
Q. Okay. And that change occurred outside of a base rate case, did it not?
A. It did.

Q. So is it your testimony that it's acceptable to change the off-system sharing mechanism outside of a base rate case, but the fuel allocation methodology shouldn't be changed outside of a base rate case?

A. What we're saying is if you change the fuel allocation process outside of a base rate case, that it has an impact on the off-system sales margins that you would collect, and but -- what was in the base, and therefore you end up with a mismatch or, you know, tracked cost of those -- the inequity between how your base was -- your off-system sales base was established and what is being collected.

Q. Are you aware of the Commission's fuel adjustment clause regulation which is set forth in 807 KAR 5:056?

A. I'm aware; yes, sir.

Q. Okay. Will you accept, subject to check, that in that regulation, Section 1, Paragraph 11 states as follows: "At six-month intervals, the commission will conduct public hearings on a utility's past fuel adjustments. The commission will order a utility to charge off and amortize, by means of a temporary decrease of rates, any adjustments it finds unjustified due to improper calculation or application of the charge or improper fuel procurement practices."

If the Commission were to determine -- and now this is the question. If the Commission were to determine that Kentucky Power has erroneously allocated a portion of its fuel costs under the FAC for the period under review in this case, is it your testimony that the Commission should ignore the provision of the FAC regulation that says rates should be decreased if there is an improper calculation or application of the fuel adjustment clause?

A. Not at all. All that we're stating is that if you're going to make an adjustment of disallowance or whatever it might be because that change in the fuel, in the -- in the allocation change to off-system sales has another impact, that in order to match everything up that it be at the same time as a base rate case.

Not -- we're not saying that you don't, you know, have the ability to make that change, just understanding that it creates a mismatch.

Q. Okay. Well, the Company doesn't currently have a base rate case pending here, does it?

A. It is going to file notice of one Friday.

Q. Okay. And so I guess it'll be filed --
A. End of December.
Q. -- in December?
A. And with the -- you know, the idea of the five-month extent -- or extension, I forget the time, it would be basically rates would go into effect roughly July 1st of 2015.
Q. Okay. And the case of -- rate case will be filed using a historic test year?
A. An historic test year of September 30th, 2014, 12 months into September 30th, 2014.
Q. Okay. So, you know, I'm trying to kind of understand your prior answer about wanting the Commission to -- if we -- if we were to determine that there was some erroneous calculation or application of the FAC, to recognize some kind of an offset, if you will, or a counter-adjustment in a base rate case, what we're talking about here are costs from January through April of 2014, and if there was a determination that there was some erroneous calculation of those costs, are you suggesting that in the -- in your next base rate case that there would be some way to offset the erroneous charges from January through April of 2014?

A. I think what we're saying, sir, is that if you were to -- if we were to calculate whatever the amount would be that the Commission felt was misallocated, whatever that might be, is that in order to try to be -- to, as neatly as possible, time everything up, that amount could be adjusted even still through the fuel adjustment clause application, be -- but be made as a one-time adjustment in, let's say, July of 2015. I'm not sure what the proper time would be, but you could make that adjustment as a one-time adjustment in sequence with when base rates are is all that we're making the statement of.

Q. Okay. I'm still not exactly clear, but let me -- are you suggesting that if the Commission were to determine that there had been an erroneous calculation of the FAC, that rather than issuing an order within the next six to eight months, that the Commission hold up that order until such time as it issues an order in your to-be-filed base rate case so that any reduction or credits that had to be paid under your FAC would seem to be -- maybe not exactly offset, but the total revenues that the Company -- it would just reduce, on a one-time basis, the additional revenues that the Company would receive

from the base rate increase?
A. Basically, yes, sir, because -- again, it's because the 15.3 million that's in base rates was based on that allocation method, and, you know, trying to make all the adjustments outside, it was trying to synchronize them all up, is going to create some costs, and that -- what you just said I think is proper.
Q. Okay. In your rebuttal testimony at page 13, the table which shows the return on equity, would you be able to provide the supporting calculations for the return on equity amounts that are shown for the years 2010 through 2014?
A. Absolutely.
Q. Page 17 of your rebuttal testimony, beginning at line 12, where you say that "not aware of any FAC proceeding where an adjustment (credit or charge) has ever included interest at any rate," would you accept, subject to check, that the Commission did order Big Rivers to pay interest on disallowed fuel costs in PSC Case 1990-360-C?
A. Subject to check; yes, sir.
Q. Okay. Based on your -- on the question and your response to the prior question, would it be safe to assume that if the Commission were to find

that some fuel costs were improperly calculated or allocated and costs were disallowed, that it's the Company's position that it would prefer to record it on its books in 2015 rather than 2014?

A.   Yes.

Q.   Okay.

MR. RAFF: Did we skip Number 7?

MS. WHELAN: Yeah.

A.   Let me just expound a little bit in thinking about that. I mean, if -- from a -- from an accounting perspective, you know, we would always much rather incur the costs in the -- in the year that -- match it up with when it occurred.

So if the Commission were to rule that, you know, there was going to be that disallowance or a change in that, what we would do, when we know that that was coming in, we would probably book a deferral of that in 2014 to match it up and then reverse that when it actually took place. It --

Q.   And what would be the --

A.   Now, if we did -- if we didn't know -- if there wasn't an order out by the time we closed our books in December, you know, it would get booked in 2015, but, you know, from a -- from an accounting perspective, you know, the idea is to match up, you know, the costs with when they incurred, and that would be in 2014.

Q. So you're saying that if you do not have a definitive decision from the Commission by December 31, 2014, that you would close your books and any subsequent decision that might affect the fuel costs would be booked in 2015 --

A. Yeah. It's --

Q. -- or is there a --

A. No, that's a good --

Q. -- point in time within 2015 that if the Commission issued an order, that you would still reflect it on your 2014 books?

A. Up until approximately -- I don't know the exact date, but approximately the third week of January, if we knew something up to that point in time, we would still book it as of 2014 'cause the books -- we normally close around the seventh or eighth workday of any month. December being the end of the year, we have an extended period of time, so approximately the third week of January.

Q. And at page 6 of your rebuttal testimony, beginning at line 19, could you read that sentence, please?

A. That starts with "Had the Company"?

Q. "Had the Company's."
A. Okay. "Had the Company's service territory experienced weather during the winter of 2014 similar to that experienced during the winter of 2013, the demand for the Company's energy would not have been nearly as high as was experienced during the winter of 2014 and the no load costs would have been lower."
Q. By that statement do you mean that either Big Sandy Unit 2 or one of the Mitchell units would not have operated if the winter of 2014 was similar to the winter of 2013?
A. Some of the units would not have. And again, you get your units and you -- whatever's available, you bid them in, but if there's not a supply, you know, for that, and so then they get denied based on the highest price, so it is possible that many of the units would not have been accepted into the -- to the bid that day.
Q. But the units would have run to make off-system sales if they were --
A. Only if there's --
Q. -- the price was accepted.
A. Only if there's a market. I mean, that's what I'm saying, with the mild weather of 2013,

there wasn't a market, so you can't run them if there's nothing to -- no one to sell them to.

Q. Do you know whether there was a market in the winter of 2013 for off-system sales?

A. That's the point, there wasn't much of a market. I think Mr. Pearce can tell you better about what the market was, but the market was, there was not much of an off-system sales market in 2013.

MR. RAFF: Thank you, Mr. Wohnhas. I have no further questions.

THE WITNESS: Thank you, sir.

VICE-CHAIR GARDNER: We'll take a short break, we'll come back at ten after 5:00.

MR. OVERSTREET: Thank you.

(Recess from 5:00 p.m. to 5:12 p.m.)

VICE-CHAIR GARDNER: Have a seat. You are still under oath, Mr. Wohnhas.

THE WITNESS: Yes, sir.

FURTHER CROSS-EXAMINATION

By Mr. Raff:

Q. Mr. Wohnhas, I have one follow-up, at least one follow-up. And if you would refer to -- I guess it was KIUC Exhibit 8, the last page, which was the revised calculation submitted in this case reflecting the projected -- I'm sorry. That was the -- the original calculation from Case 2012-578 of the increase in cost from January 2014 through June of 2015 for the middle column, Mitchell Transfer Overlap Period, and it was originally projected to be 5.33 percent. And then the KIUC Exhibit 1, which was the revised calculation that was submitted in this case, which shows that increase going from the 5.33 percent to the 12.81 percent. Do you see those two?

A. I do, sir.

Q. And it was my understanding that you said the increase was a result of the polar vortex and the no-load costs?

A. No. Well, I mean, the -- we added on an annual basis $38 million of -- of no-load costs, and what we said is that for the January -- we're saying for the January through April time period, the increase in that no-load cost there was primarily contributed to the polar vortex.

Q. Okay. Well, how much of the no-load costs were included in the original calculation leading up to the 5.33 percent?

A. I don't know. We didn't go back and -- I don't have that number.

Q. Do you know whether any were included in there?

A. Well, it would. We would have had no-load cost, because there was no-load cost always during -- you know, in our cost of service, so I would have to -- I'd have to go back and see what that amount is.

Q. All right. Could you do that for the -- how much of the no-load costs were included in the original exhibit which shows the 5.33 percent increase and how much were the no-load costs included in the revised exhibit showing the 12.81 percent increase?

A. Yes, sir.

MR. RAFF: Thank you. I believe that's all the questions we have at this time, Your Honor.

VICE-CHAIR GARDNER: Do you have any questions? Do you have any questions?

EXAMINATION

By Commissioner Breathitt:

Q. Mr. Wohnhas, you've testified that this way of calculating the FAC with no-load costs has been used by the Company for 30 years.

A. At least 30 years, yes.

Q. And by the Company, you -- do you mean Kentucky Power and -- and all of AEP subsidiaries?

A. Yes, all -- I mean, Kentucky Power, but then the other subsidiaries -- subsidiaries do the same methodology.
Q. Since you've been with Kentucky Power, have there been any instances that you recall where there's been a weather situation or any other type of situation that caused such a noticeable jump?
A. I mean, not that I'm aware of.
Q. And I might not be artfully asking the question, but -- so this -- so what I just heard you say, that this may be the first time this has ever -- something like this has ever happened?
A. Well, you also have to realize is that this is the first time, though, that we have had, you know, two additional units, you know, the two Mitchell units, and, you know, those Mitchell units, you know, not only for the purposes that I've mentioned, off-system sales, but those units during this polar vortex were a hedge for Kentucky Power.
In Mr. Pearce's testimony, he showed that without having Mitchell available during the months of -- I think it was January through March, that we would have incurred roughly 9.9 or almost $10 million in additional costs that customers would have paid in fuel by having to go out to the market

and purchase energy instead of having Mitchell. So that -- having that excess capacity was a hedge during this polar vortex.

It's also having the ability of these units available is that if a unit goes down. If a unit is currently being assigned to an off-system sale -- let's say that as you come down -- just for an example, let's just say that Big Sandy 2 is currently being assigned to an off-system sale based on the economic dispatch, and let's say that Mitchell was currently being used to provide the internal load. If that Mitchell Unit 1 would go down, then the Big Sandy 2 unit would then automatically be used -- be available to go to serve that internal load versus any -- or whatever the cheapest addi -- supplemental power would be to serve that.

So that having these units is a hedge against, you know, things that would happen like that. So it's -- and that's probably more important than, quote, the off-system sales.

Q. If Kentucky Power had still been in the pool, is there any way to know what -- no way to know? You can't put the genie back in the bottle?

A. No, you can't -- that's -- that's correct.

COMMISSIONER BREATHITT: I think that's it. Thank you.

EXAMINATION

By Vice-Chair Gardner:

Q. Good afternoon Mr. Wohnhas.

A. Good afternoon.

Q. First, KIUC Exhibit 4, which is the no-load costs, November 12 through April 14, did you-all compile that, those numbers?

A. I didn't number mine. Which one is Number 4?

MS. HARWARD: That's okay.

A. Yes, this one here. Yes, we provided --

Q. Okay.

A. -- those numbers.

Q. I'd like you-all to, in a post-hearing data request, update that to now or as -- what the current information is.

A. Sure.

Q. By month. Just same format, exactly the same.

Now, let me go back to the -- to the stipulation and the hearing that we had with respect to -- I'll just call it the Mitchell case, which is I guess 2012-578. And in that case we started the hearing and then there was a break and then we came

back, and in the meantime the stipulation -- there was -- there was thinking at the time the case started that there was going to be a stipulation, and then there was a break and then we came back later for the hearing on the stipulation. Is that -- is my memory correct on that?
A. I know that we provided a draft of a stipulation, I believe it was on July 2nd or -- I'm just not sure of the dates. That was whatever.
Q. Okay.
A. But then we continued with the hearing.
Q. Okay.
A. I just don't remember the actual chronology.
Q. The -- do you remember when, at a hearing, and I believe it was early -- it was in this case when it first started, that a -- the fifth set of data requests was actually asked, which was to prepare the chart that we've been referring to, which shows the fact --
A. Five-ten?
Q. Pardon me?
A. Five-ten?
Q. Yeah, yeah, yeah. So you're -- you're -- you recall that?
A. Yes, sir.

Q. Subject to check, this was filed on the same day that the -- and I could be wrong, as the stipulation was filed? Is that possible? This says June 26 is when this was --

A. That was the order dated June 26, which -- it could have been real close to that date.

Q. Okay.

A. Normally we have ten days or so, so --

Q. All right. In any event, this -- you're aware, aren't you, that this stipulate -- this data request was important to the Commission?

A. Yes, sir.

Q. Okay. And, in fact, it was actually -- the number, the 5.33 percent, was actually mentioned in the order approving the stipulation. That wouldn't surprise you, would it?

A. Not at all.

Q. Okay. Now, did I understand you to say that basically from the Company's perspective, this is fair because you-all were giving -- you-all were giving up roughly, you know, the -- you know, 138 to 44 million, you -- 44 million, you were giving up a lot of potential revenue that you would otherwise be entitled to if it were not for the stipulation?

A. Yes, because part of that stipulation, as you recall, was that we pulled the base rate case, all right, and basically now we're going to file it coming up, but that was part of that give was pulling that rate case --

Q. And --

A. -- to get the full recovery of Mitchell.

Q. And so you -- so it's -- so this is fair, and that makes it seem as if at the time you-all knew that this -- that there would be no-load costs on these off-system sales where the Company got 100 percent of it above the 15 million, that there would be -- it makes it seem like you-all are aware -- were aware at the time that there would be no-load costs, because it's something that had happened all along.

A. I'm may -- let me -- I'm not sure I understand exactly what you're saying, but you're right, no-load costs has always been assigned to internal.

Q. And the Company knew about the concept of no-load costs at the time of the --

A. We knew of --

Q. -- at the time of the --

A. Sure.

Q. -- stipulation?

A. We knew of the concept of no-load costs, but was under -- and looking at, you know, what we thought was going to happen, did not see that those in total no-load costs would change.
Q. Okay. And -- but you knew that -- although you were getting 100 percent of the profits, you knew that the no -- because -- and you had all these extra -- you had two more units, you had the 800 megawatts of Mitchell to add to the fleet. Even without the -- even without the polar vortex, you-all knew that there were going to be no-load costs assigned to customers because there would likely be an increase in off-system sales, because now you had now Big Sand -- I mean now Kentucky Power owned an additional 800 megawatts.
A. The part that that -- that I think is incorrect there is that we did not know that there would be additional off-system sales. We only put in the provision for 100 percent of the recovery over $15 million as just an offset to, again, giving up 60 percent of Mitchell, and the fact that if there was an opportunity, we could make that, but we did not have anything -- and matter of fact, in some of the data requests that was filed about what we thought earnings would be and such, and it was under

confidentiality, but the idea was the only thing that we made an adjustment for was the idea instead of getting only 40 percent of what we thought the current sales level was forecasted, we'd get the other 60 percent. So we did not anticipate that we would have additional off-system sales.

Q. Okay.

A. We were just -- that was just a hedge that if it was there, we could do it.

Q. Okay. And what amount did you figure in as you budgeted this of off-system sales there would be at the time? You just said that you didn't --

A. Sure.

Q. -- expect it to be as great as it was, so what amount did you anticipate at the time that the customers, that the consumers would be responsible for?

A. We showed an additional $10 million of margins, which would be picking up the additional 60 percent if the -- if the basically market was the same as the previous year.

Q. Okay. So -- and did you -- did -- was that shown in any of these calculations, that 10 million?

A. No.

Q. Okay. Did -- when did you personally have

your first discussion about no-load costs?
A. November of 2013.
Q. Is that the first time you heard of it?
A. It was actually the first time I had heard of no-load costs.
Q. Okay. And how did you hear about the concept of no-load costs?
A. Witness Pearce, as he, you know, came down to discuss just as -- with Kentucky Power how -- the idea of a few minor changes, as he can describe and was in his testimony, were going to happen around different things that would be included in no-load costs, and so that was the first time.
Q. Okay. And so then clearly -- if you didn't know about it until November of '13, then clearly Commission Staff nor none of the parties would have heard the concept from you.
A. Not from me.
Q. It's --
A. And I don't know -- and again, I don't -- not been able to talk to my predecessor, but I -- you know, I don't -- I never remember him discussing it either, so -- but I don't know if he was ever aware of that terminology either.
Q. Okay.

A. You know, there were a handful in Columbus that dealt with it on a daily basis that, you know, were aware, but --
Q. So you didn't -- you didn't understand when you were -- when you signed the -- when you signed -- when you proffered the testimony to accept the stipulation, you didn't -- at that time you didn't know about the no-load cost concept, so there was no way you could have apprised the Commission, Commission Staff, or any of the parties about the risk that 100 percent of the sales -- that there would be an incentive on you-all, plus you've got Mitchell to run, and that the customers would be paying a certain level for every dollar that got sold in off-system sales, 'cause you didn't understand the risk at that point?
A. We made contacts, you know, as -- again, as Witness Allen as I -- and I were in the settlement discussions, you know, we made contacts as we were having -- in the settlement back with folks in Columbus, but we never got down, the best I know, to the detail of down that deep about no-load costs.
Q. But it wasn't mentioned at all?
A. Not that I'm aware.
Q. Okay. Even in your internal deliberations

about whether -- how to -- how to negotiate this, you don't have any recollection of that?

A. I don't -- I don't have any recollection.

Q. And, in fact, it was November that you realized that that would -- that you heard about the concept for the first time?

A. And in those discussions there was still no indication that it would have any effect on anything that was established through the stipulation and settlement agreement.

VICE-CHAIR GARDNER: Okay. So -- okay. I think that's all I have. Thank you.

COMMISSIONER BREATHITT: May I -- may I ask one quick?

VICE-CHAIR GARDNER: Sure.

REEXAMINATION

By Commissioner Breathitt:

Q. Mr. Wohnhas, you just testified that you became familiar with the term no-load in November of last year?

A. Yes, ma'am.

Q. But the Company has been using the -- this -- the accounting method for 30 years?

A. Yes.

Q. Was it just buried deep in the Company?

A. Yeah, there -- you know, there's not an -- you know, when you think about, you know, fuel is Account 501 when we talk about fuel. You know, there's not a separate account number for no-load costs. There's not -- you know, it's not that -- it's just a part of that fuel cost, and, you know, we have dispatched under -- I mean, we've allocated based on the economic dispatch principle long before -- you know, it probably wasn't even called no-load costs back when it was initially there.

As you've heard this morning, you know, I think in the LG&E/KU, they have that cost, but they don't -- and they said they don't use it -- they don't use the terminology no-load, so --

COMMISSIONER BREATHITT: Thank you.

THE WITNESS: You're welcome.

VICE-CHAIR GARDNER: Mr. Overstreet.

MR. OVERSTREET: Okay. Thank you.

REDIRECT EXAMINATION

By Mr. Overstreet:

Q. Mr. Wohnhas, I want to see if I can clarify a few things and then discuss a few matters with you, if I might. I think you were asked, and it may have been -- I think it may have been Mr. Kurtz, about who dispatches Big Sandy and Mitchell and Rockport

and the Company's units, and I think you indicated that that was, quote, Columbus, i.e., AEP; is that accurate?
A. No. It's -- you know, the people in Columbus that I referenced to are the ones that offer those units into PJM, but PJM actually dispatches the units.
Q. Okay.
A. So slight clarification.
Q. And we heard sort of the same sort of thing from some other PJM utilities earlier today.
A. That's right. You know, our people in Columbus just offer the available units in each day.
Q. And Mr. Raff was asking you some questions about the fact that the sharing mechanism, the 60/40, 60 percent to the Company's customers, 40 percent to the Company, of off-system sales margins was changed during the -- as a result of the July 2nd stipulation and settlement agreement. Do you remember that discussion?
A. I do.
Q. Now, that sharing mechanism only relates to off-system sales margins above and beyond the 15.3 million that are baked into base rates; isn't that correct?

A. The 100 percent?
Q. Yes.
A. Yes. That's correct.
Q. Okay. And isn't it true that as part of the stipulation and settlement agreement, the Company agreed to withdraw its then pending rate case?
A. That is correct.
Q. So this change was made in the context -- even though it wasn't in exactly that case, in the context of a rate case?
A. Yes, because the rate case was for the purpose of getting full recovery of Mitchell, and as part of the settlement, these other changes were made and we pulled the base rate case.
Q. Okay. And the -- Mr. Raff was asking you some questions about, I guess for lack of a better description, you know, timing of any -- of the accounting effects or the booking of any change that the Commission might make in connection with this case, the -- when the Company would like -- you know, does it basically want to book it in 2014 and 2015. Do you -- do you remember that discussion?
A. I do remember that discussion, yes.
Q. Okay. Now, does the Company believe that its allocation of no-load costs in the manner that it

has done during this review period is incorrect or serves as a basis for the Commission to make such a disallowance, if you will?

A. Absolutely not. I mean, we -- I would still hold that, you know, because of the stipulation and settlement agreement and all the parameters of that, you know, that there should be no changes prior to July 1st, 2015.

Q. And so your discussion with Mr. Raff about when and whatnot, were you referring to the -- any sort of charge in connection with that or were you talking about the change in the methodology for allocation?

A. The change in the methodology.

Q. Okay. Now, Mr. Wohnhas, I think you've testified on several occasions here this afternoon that to your knowledge the Company's been allocating no-load cost -- no-load costs in this fashion for approximately 30 years, if not longer.

A. Yes, sir.

Q. Okay. And did the Company believe that that allocation was fair, just, and reasonable ten years ago when it was doing it?

A. Absolutely.

Q. And so that allocation and the fairness of

that allocation has nothing -- it wasn't changed by the fact that there was a July 2nd stipulation and settlement agreement; is that true?
A. Not at all.
Q. Okay. And in talking in terms of whether the allocation is fair or not, and I understand Mr. Pearce will discuss some -- maybe some more the intricacies of the allocation, but is it fair -- well, strike that.
What do the customers get for the fact -- by paying these no-load costs -- no-load costs?
A. Well, they get a number of things. You know, one, they get a reliable unit that's going to be around for 25 years. All right. Big Sandy 2 is going to go away and so we're going to have that unit.
Two, during this time that they're there, those units are a hedge as to events such as a polar vortex. And having Mitchell on there, as Mr. Pearce will describe, they saved the comp -- the customers about $10 million.
As I stated before, it's a hedge on the fact that if you have units and you -- and it happens, as units go down during the day for, you know, a forced outage due to a tube leak, all right, that might

happen, and so now it's down, you know, you have those other units that then are taken -- if they're least cost, then taken and provided to your internal customers versus the off-system sales.

Kind of went blank from that point on. I'm sorry.

Q. That's fine. So the no-load costs give the customers the first call on the Company's generating facilities?

A. Absolutely.

Q. And this acts as sort of like an insurance policy?

A. It does. It's a hedge, yes.

Q. And in the first four months of 2014, Mr. -- is it -- is it your understanding of Mr. Pearce's testimony that the -- that notwithstanding the additional no-load costs that were incurred following the Mitchell transfer and as a result of the polar vortex, the Company is $9.9 million better off than if it didn't have Mitchell and had to go to market?

A. Yes.

Q. Okay. I'm sorry. Let me strike that.

That the customers are $9.9 million better off?

A. Yes. Yeah, customers are. Yes.
Q. Okay. And Mr. Kurtz was talking about the Company's increase in off-system sales margins following the Mitchell transfer. Do you remember that discussion you had with him?
A. Yes, sir.
Q. Did anything else increase effective January 1, 2014?
A. Yes. You know, we had the -- you know, again, the equity of Mitchell being added to our base as being an operating company was -- you know, and the costs associated with those was incurred by the Company.
Q. So these margins went up, but also the Company's -- the amount of equity --
A. Equity balance went up, yes.
Q. And so the Company's return on equity was affected?
A. Yes, it was.
MR. OVERSTREET: I think that's all I have. Thanks, Mr. Wohnhas.
VICE-CHAIR GARDNER: Mr. Kurtz.
MR. KURTZ: No questions, Your Honor.
MR. COOK: I have a few questions.

RECROSS-EXAMINATION

By Mr. Cook:

Q. Mr. Wohnhas, I believe you said earlier that there's a handful in Columbus who were aware of the concept of no-load costs, correct?

A. Yes, I did.

Q. Okay. Kentucky Power is an independent company, is it not, corporation?

A. I mean, yes, we're part of --

Q. Incorporated in the state of Kentucky?

A. That's right. But we're part --

Q. Yes.

A. -- of the -- the AEP system.

Q. Right. Okay. And this handful of people in Columbus, Ohio, who were aware of this concept, do they work for the Serv. Co.?

A. They are -- they are an AEPSC employee, but they commun -- we communicate with them regularly with all types of -- whether it's that group or another group.

Q. Exactly.

A. Yeah, we do --

Q. And isn't it true that Kentucky Power relies to a very great degree on the judgment, expertise, and experience of Serv. Co. employees?

A. Employees within that department, employees at -- in accounting, employees in tax. We do not have all those employees sitting here under Kentucky Power, so yes, we do --

Q. Exactly.

A. -- rely on them.

Q. Exactly. And this handful of employees in Columbus, did any of them testify in this case?

A. Yes. One of them is Mr. Kelly Pearce.

Q. All right. Is the Company obligated by Kentucky law to provide electric service to its native load ratepayers?

A. I'm sorry. I didn't quite catch that question.

Q. Is Kentucky Power obligated by Kentucky law to provide electric service to its native load ratepayers?

A. Yes.

Q. Okay. And in the event the Commission should agree with the KIUC and AG recommendation, would you agree that an interest penalty should be assessed in addition to that?

A. No, I do not.

Q. And why is that?

A. Again, subject to check on what Mr. Raff said

is maybe a 1990 case, it's not been something that has ever been done as a precedent.
Q. Uh-huh. Would Mr. McKenzie have known about no-load costs?
A. Who?
Q. Mr. McKenzie. I'm sorry. Munczinski? Am I --
A. Oh, Mr. Munczinski. I'm sorry.
Q. I apologize for not pronouncing it --
A. That's okay. You mean prior to this --
Q. Yes.
A. -- to this thing? I believe he was. All right. I can't -- I can't answer definitively.
Q. Now, Kentucky Power filed a rate case that I believe under redirect from your attorney you just discussed, and that was withdrawn under the terms of the settlement, correct?
A. That is correct, sir.
Q. Okay. Wasn't the filing of that case for the purpose of prodding the parties to settle?
A. No. Not at all. It was for the purpose of -- our idea going in was that we wanted 100 percent of Mitchell, and so in order to get that, we had to file that rate case, even though the transact -- the 578 was going on, I mean, our

purpose was to get the full recovery of Mitchell.

MR. COOK: No further questions.

VICE-CHAIR GARDNER: Mr. Raff.

MR. RAFF: Yeah, just one.

RECROSS-EXAMINATION

By Mr. Raff:

Q. Following up on a question that your counsel asked you, which I think was that the Kentucky Power ratepayers benefitted during the months of January through April by having the Mitchell unit because they saved 9.9 million in costs that otherwise would have been incurred if they had to buy power from the market; was that --

A. Yeah. Mr. Pearce has a -- has a calculation in his testimony that, you know, looks at if Mitchell had not been in our portfolio, and so at the times of using Mitchell, if we'd've had to gone out to the PJM market during those hours, at the prices that happened, that it would have been approximately $10 million.

Q. Okay. Could you refer to your response to Staff's first --

A. Staff, which --

Q. Yeah, Staff's first set of data requests, Item 29. There was a four-page response and then

there's an attachment, and it's Attachment Number 2, page 1 of 1.
A. Yes, sir.
Q. And it's titled No Load Costs November 2012 through April 2014 for Kentucky Units?
A. Yes, sir.
Q. And if I look at the columns Mitchell 1 and Mitchell 2, it shows that for the four months of January through April of 2014 that the no-load costs for Mitchell 1 were 5,675,000, and Mitchell 2 7,479,000, and if I add those two together, I get 13.1 million?
A. Yes, sir.
Q. Is that about right? So are we saying that by having Mitchell for the first four months of 2014, the ratepayers saved $9.9 million by not having to buy power on the market, but they paid out 13.1 million for no-load fuel costs?
A. I don't think you can make that correlation, but I'll ask you to defer that to Mr. Pearce and let him explain that, if you would, please.
Q. So why don't you think you can make that? Do you have a reason for --
A. Well, I think Mr. Pearce would be better to answer that, and I don't want to lead off in

something that I'm not fully aware of.
Q. But you said you don't think you can make that correlation. Do you have a reason for saying that you don't think you can make that correlation?
A. It's because I don't fully -- I don't know all the details on how he calculated his 9.9, so it's better for him to answer the question.
Q. So would it be more accurate to say you don't know whether you can make the correlation or not?
A. That would be fine. Mr. Pearce would be one that can make that --
MR. RAFF: Okay. Thank you. No further questions.
VICE-CHAIR GARDNER: Any further?
MR. OVERSTREET: Just one question.

REDIRECT EXAMINATION

By Mr. Overstreet:
Q. Mr. Wohnhas, when the com -- when the -- through the course of a fuel adjustment clause proceeding it turns out that the Company has underrecovered its fuel costs, does the Company get to charge its customers interest on that underrecovery?
A. No, it does not.
MR. OVERSTREET: That's all I have.

VICE-CHAIR GARDNER: Any further questions of this witness? Okay. You may step down.

THE WITNESS: Thank you, sir.

VICE-CHAIR GARDNER: Sure.

MR. OVERSTREET: Our next witness, Mr. Vice-Chairman, is Kelly Pearce, and Mr. Gish -- my colleague, Mr. Gish, whose name I almost forgot, will present him.

* * *

KELLY DOUGLAS PEARCE, called by Kentucky Power Company, having been first duly sworn, testified as follows:

VICE-CHAIR GARDNER: Please have a seat. State your full name.

THE WITNESS: Kelly Douglas Pearce.

VICE-CHAIR GARDNER: And with whom are you employed?

THE WITNESS: American Electric Power Service Corporation.

VICE-CHAIR GARDNER: And what is your position with them?

THE WITNESS: I am director of contracts and analysis.

VICE-CHAIR GARDNER: You may ask, Ken.

MR. GISH: Thank you, sir.

DIRECT EXAMINATION

By Mr. Gish:

Q. Dr. Pearce, did you have data responses and rebuttal testimony filed in this case?

A. I do.

Q. And do you have any changes or corrections to your data response -- data request responses or your rebuttal testimony?

A. I do not.

Q. If I were to ask you the same questions today that were asked in your rebuttal testimony or in your data requests, would you give the same answers?

A. I would.

MR. GISH: Mr. Vice-Chairman, Dr. Pearce is available for cross-examination.

VICE-CHAIR GARDNER: Mr. Kurtz.

MR. KURTZ: Thank you, Your Honor.

CROSS-EXAMINATION

By Mr. Kurtz:

Q. Mr. Pearce, you've obviously testified about no-load costs, correct?

A. I'm sorry?

Q. You've obviously testified about no-load costs, correct?

A. In this case I've submitted rebuttal

testimony that pertains to no-load costs.

Q. Do you agree that no-load costs are theoretical costs?

A. No-load costs, as I provided in one of the exhibits to my testimony, KDP-4, it's not theoretical in the sense that this is values that we submit into our daily PJM offers. It -- these are screen shots from in market.

I will accept the fact that they are theoretical in the standpoint that physically most generation plants cannot produce in a stable manner at zero megawatt output.

MR. KURTZ: Okay. Your Honor, if we could have marked as KIUC 10.

COMMISSIONER BREATHITT: Thank you.

VICE-CHAIR GARDNER: Thank you.

COMMISSIONER BREATHITT: This is good.

MR. OVERSTREET: Thanks, Mike.

COMMISSIONER BREATHITT: 2011.

Q. Do you recognize this as a PJM document?

A. It looks to be -- is this -- what part of -- what manual or -- is this?

Q. It's No-Load Definition: Educational Document PJM. Looks like it was published in 2011, down at the bottom.

A. Okay. It references Manual 15.
Q. Okay.
A. But I'm not sure this is a manual.
Q. I'm sorry. What?
A. I said I -- okay. I see it references Manual 15, I'm just not -- I'm not sure it's a manual.
Q. Now, this PJM education document I've highlighted in yellow, tell me -- I'll read it, tell me if you agree. "The book Fundamentals of Power System Economics defines no-load cost as the theoretical cost for a unit '... to remain connected to the system while supplying non electrical power, the no-load cost represents the cost of fuel required to keep the unit running.'"
Do you agree with that statement?
A. Yes.
Q. Okay. "Such a mode of operation is not possible for most thermal generating units."
Do you agree with that?
A. Yes. And as you noted, it says "most thermal generating units."
Q. Okay. So again, this is the amount of fuel to burn to make steam to turn the turbines to get it synced up to the grid but produce zero megawatt hours?

A. That's a reasonable interpretation.
Q. Okay. And a unit cannot operate at that level, it has to operate at something higher, called its minimum, correct?
A. Kentucky Power's units, that is true. They -- on a stable matter, they have to operate at their minimums.
Q. Okay.
A. The AEP system actually does have some units that have been configured that they can operate at that level.
Q. Could Kentucky Power sell any electric -- or make any electricity without incurring no-load costs?
A. It can -- it cannot produce -- by definition, that's the level at which it cannot produce any megawatt hours.
Q. But can you produce any electricity without incurring the no-load costs?
A. No.
Q. Okay. Is that why you have referred to it in discovery as a fixed cost?
A. Yeah, it can be kind of -- it's one consideration called a fixed-type fuel component.
Q. The -- you've testified about LG&E and KU's

process for allocating fuel costs between native load and off-system sales, is that correct, on page 17 through 18 of your testimony?

A. Yes, I did.

Q. It's true, isn't it, that KU and LG&E are in a considerably different situation than Kentucky Power in a lot of ways?

A. You'd have to be more specific.

Q. Kentucky Power has a lot of excess generation for sales in the off-system market and KU does not. Would you agree with that?

A. I know during this, I'll call it overlap period, Kentucky Power does tend to be surplus. I have not looked at the relative capacity position of LG&E and KU to comment.

Q. Have you looked at the outcome of their fuel cost allocation through the fuel adjustment?

A. No.

Q. Well, then how could you testify that "not far afield from Kentucky Power's method?" Are you talking about the method, not the result?

A. Yes. And if it is the methodology, and as I felt like I was reinforced being in the courtroom today when I heard from them, they do an allocation of incremental costs from the top of their supply curve just similar to what AEP does as I referenced in -- just in illustrative fashion in KDP-2, Exhibit KDP-2.

MR. KURTZ: Okay. Your Honor, one, I think final exhibit, if we could have it marked as KIUC 11.

Q. Take a minute to familiarize yourself. What we have done is just simply taken the fuel adjustment filings for KU and LG&E for the first four months of 2014 and then compiled the results on the front.

Let me know after you've had a minute to take a look at the fuel schedules.

A. I'm sorry, sir. Are there certain pages you want me to reference out of this or --

Q. Well, let's just go --

A. -- read the whole thing?

Q. Let's just -- okay. No. No. That's fair. Let's -- okay. January 2014 for KU, do you see the front page of their filing with the Commission, the fuel rate, Fm, S -- Sm is $32.04 a megawatt hour for native load?

A. Yes.

Q. Okay. Then on page 2 of the filing, KU shows that they made inter-system sales of $3,366 during

January. Do you see that on page 2 of 6?
A. Yes.
Q. And then the megawatt hours associated with that are 171,000 on page 3 of 6. So for that month, just a simple 3,366 divided by the 171 equals $19.68 a megawatt hour for the fuel cost off-system?
A. Okay. I saw the 3,366, and then what was the other one you were pointing to?
Q. The volume is on page 3 of 6, inter-system sales including interchange-out.
A. Okay.
Q. 171,000 kilowatt hours or 171 megawatt hours.
A. Okay.
Q. Okay. So they -- so in that first month KU sold off-system for cheaper than on-system, but it was only $3,000 worth of power.
A. Okay.
Q. And then if you look in February, March, and April, they had no off-system sales fuel costs. So they had zero. Do you see that?
A. I'm seeing no interchange-out dollars in February. What's -- I'm seeing zero, but then in the next page, for February, I'm also seeing some 78,000.
Q. That is a funny little anomaly, but --

A. I'm kind of curious that -- why they got zero for dollars but 78,000. So it looks like they're --
Q. That's true. It's really --
A. They are allocating some power for free. That is a good deal.
Q. Small amount of generation. Maybe we can look into --
A. Sure.
Q. -- that anomaly, but in contrast to KU selling $3,336 worth of power in the first four months, Kentucky Power made a profit, not the sale -- not the gross -- not the sales price, but a profit on off-system sales of $49 million during the first four months; is that right?
A. You're saying Kentucky Power made a $49 million of off-system? That's the number as I understand it.
Q. Profit. Not gross revenues but profit from off-system sales.
A. Sorry. Yeah, margins.
Q. Margins. Now, LG&E, let's just -- if we just -- just take a look at January for LG&E. They had native load fuel adjustment of $20.49 a megawatt hour. Do you see that?
A. What page are you on?

Q. The LG&E schedule, Form A, page 1 of 5. So their actual fuel costs for native load that month --

A. Sorry. For what -- which month?

Q. January.

A. January. Okay.

MR. GISH: Just so we're clear, Mr. Kurtz, this is the one that was filed and -- or received by the Commission on February 21st --

MR. KURTZ: Yes.

MR. GISH: -- 2014?

MR. KURTZ: Yes.

MR. GISH: Okay.

A. Yes, I see that.

Q. Okay. So that was the amount for native load, then they have inter-system sales or off-system sales of a dollar amount of 3,925,000. Do you see that?

A. Yes.

Q. Okay. And the volume was 87,467 megawatt hours?

A. Okay.

Q. Okay. So the fuel cost assigned to off-system sales for LG&E in that month was $44.87. Do you see that? Do you want to check the math?

Three nine -- 3,925,186 divided by 87,467, $44.87 a megawatt hour.

A. Yes.

Q. Okay. So they are -- and we can -- they -- LG&E is allocating higher than fuel -- higher fuel costs to off-system sales than they allocate to native load, at least in January, correct?

A. It -- they are allocating some cost. Does that line C, the interchange-out, include any purchases that they made that they then subsequently allocated to off-system?

Q. Purchases are in the generation chart for the cost. It's on page 2 of 5. You see the purchases are up there, and then the purchase of kilowatt hours on page 3 of 5, so that's separately identified.

A. Yeah. The purchases coming in, but then the -- okay. So purchases --

Q. So let's -- assuming that LG&E and KU have a methodology that is in the ballpark or not far afield from Kentucky Power's, the result is certainly different, isn't it, in that KU doesn't even sell any power off-system, at least in the first four months, and that LG&E allocates a higher fuel cost to off-system sales than to native load?

A. On a -- when you allocate your highest incremental cost to off-system sales, that can be a value that is either above or below your average cost. For example, on my exhibit KDP-4, page 2 of 2, where we have just illustrative blocks of our supply curve, if you are only allocating a few megawatts out of a given unit as I show on that page, you know, if at -- a given unit is close to 400, the cost of those last few megawatts are approximately $30. That may or may not be below your average cost. Now, as you allocate more, the incremental cost can go down. But to me that's not that surprising that it still references the same methodology as AEP uses, understanding that the volume of off-system sales is less.

Q. And in contrast, Kentucky Power routinely, during the first four months of 2014, allocates lower fuel cost to off-system sales than to native load, correct?

A. Well, as I said, as we allocate incremental cost to off-system, because that -- working our way down the supply curve, electing the highest cost to off-system, then yes, it works out to be, if you include the no-load cost, a higher cost allocation on an average cost basis.

If you remove the no-load cost -- on page 19 of my testimony I have excluded the no-load cost for the four months and showed that the incremental cost allocated to off-system sales in all four of those events -- those months, as analyzed by the KIUC witnesses, is actually higher than the average remaining cost, and our internal load customers get the benefit of the lower cost.

Q. Well, but native load customers are paying no-load costs.

A. They are paying no-load costs, and with that they get the benefit of all six of the units always available to serve their internal load, just as LG&E and KU, what I heard this morning, they say the same rationale.

Q. You know, do you think the Commission should be -- in deciding which methodology to approve and which method is most reasonable, should be concerned with the end result of the process and does it -- does it yield a reasonable result?

A. I think, looking at the result is certainly a valid data point to examine, but if the methodology is sound -- Kentucky Power finds itself in somewhat of an overlap period in that it was, I believe, recognized by the parties, and I wasn't directly involved with the settlement, that during this period, with the opportunity to acquire Mitchell and Big Sandy 2 not having yet retired, that there would be surplus power. It's still always made available first to our internal load customers, but that would drive a larger magnitude of off-system sales.

Q. If you were just serving your native load, you wouldn't run all six units, would you? If you're going to say maybe the polar vortex in January, let's just talk about April. Would you need all six units to serve native load in April of 2014?

A. What I found interesting is, again, from our perspective, we allocate a lot -- a portion of every single unit that's online in a given hour to our internal load. So from our perspective, they are all serving internal load, and they are all available for it.

When I looked at the method offered up by KIUC, I also noted that every single month of the four months they allocated at least for some hours a portion of every single unit to internal load. So there was always the need sometime during every month of the audit period, at least the first four months of this year, for all six of the units.

Q. Did you answer my question? In April of 2016 [sic], if you just were serving native load, you wouldn't need 2,250 megawatts of generation to serve a native load of, in April, what, 800 megawatts or something?

A. And what I'm saying back is that you can't really look at it from the context that based on the settlement, it was understood that until Big Sandy 2 ultimately retires, the company is going to have about 2,250 megawatts. We offer the units into PJM. The PJM does the dispatch on the units. In fact, we cannot withhold the generation. So they're doing the dispatch.

And what I could say right now, it's Wednesday, I can't tell you Friday which units Kentucky Power customers are going to need or not need. Anything could happen to one of our units. PJM is going to control how much the units dispatch. We can forecast the load, but we don't -- we don't know for sure what it is.

I thought I -- perhaps it would help to explain that if, you know, units are offered in day ahead and they forecasted that the customers don't need at least one megawatt out of a unit, then they basically carve it off and don't make any of it available for internal load. AEP does not do that. We look after the fact and allocate always the cheapest between any purchases and the units to internal load. That's what we do after the fact.

And particularly this coming winter, Big Sandy 2, as a glide path disposition unit, could have an event at any time. It's going to take just throwing a turbine blade or something that the unit's not there for our customers, and they are going to need every bit of the remaining units. So you just don't know from one day -- you know, you can look backwards. I didn't need my car insurance driving down here because I didn't get in a wreck, but looking forward for the future, the company has an opportunity now to basically have a hedge of all six units.

Q. Now, PJM requires that, what, 15 percent reserve margin for the companies, 15, 16 percent?

A. The installed reserve margin, it might be closer to 16 percent.

Q. Okay. And Kentucky Power has a 57 percent reserve margin for the 17-month overlap period?

A. I haven't been involved in the RRP case. I could say that over the six-month review period, their peak was about 1,650 megawatts in January, during the polar vortex.

They have, when everything is online -- and of course, not all the units are online at all times. But if you have all six units on at maximum capacity, that's 2,250. That works out to be about 36 or 37 percent more generation that they have load.

Q. Would you -- would you agree with -- I went through this with Mr. Wohnhas. The no-load costs for Big Sandy 2 in April 2014 were $4.25 million. It's on KIUC Number 4, or you can just accept that number subject to check. Big --

A. I'm going to pull it up.

Q. Okay. KIUC 4, Big Sandy 2, no-load cost, April of '14.

A. Which Staff data request?

MR. GISH: It's KIUC Exhibit 4.

THE WITNESS: Oh.

MR. GISH: Are those up there still?

MR. WOHNHAS: No, I didn't number them.

MR. GISH: May I approach the witness?

MR. OVERSTREET: Here it is. I've got it.

THE WITNESS: Okay. Thank you.

A. Okay.

Q. You see the 4.25 million no-load cost?

A. For Big Sandy 2, yes, I do.

Q. Okay. If Big Sandy 2 in that month served one megawatt of native load, is it correct that that one megawatt would be charged $4.25 million?

A. See, from our allocation methodology, the unit would have never served one megawatt. What it would have served is down to the minimum that the unit can operate, which is 300 megawatt hours for every hour that it's online. That's how much the unit Big Sandy 2 served our internal load customers.

Q. Well, I'm not saying -- I'm saying if one megawatt of Big Sandy 2 went to native load. It could have been operating at its minimum the whole time serving off-system sales, but if one megawatt went to native load, wouldn't native load be charged 4.25 million?

A. And I'm saying when you say if one megawatt went to off-system sales and I'm --

Q. No, went to native load and the rest --

A. Oh, I'm sorry.

Q. -- went to --

A. If one megawatt went to native load, how -- what I'm saying is, we don't allocate just one megawatt to native load, so what is -- under what's your -- what's your framework for saying one

megawatt would have gone to --
Q. Well --
A. -- to internal load?
Q. This unit, Big Sandy 2, in April actually served -- this is KIUC Number 2. Thirty-nine point five percent of the generation went to native load and 60 percent of the generation went to off-system sales.
A. Okay.
Q. Okay? Let's just use that. Even though 40 percent -- only 40 percent went to native load, 100 percent of the 4.25 million was paid by native load; is that correct?
A. That is -- that is correct.
Q. Okay. Now, my hypothetical is: What if the 39.5 percent went down to one percent? The answer would still be the same, native load --
A. And my answer --
Q. -- would pay all the no-load costs?
A. It wouldn't have gone down to one percent under our methodology.
Q. What's the lowest it could have gone to?
A. The economic minimum on Big Sandy 2 is approximately 300 megawatts, so whenever it's online, at least 300 megawatts of it, in general, is

being allocated to internal load, along with the cost at 300 megawatts, which is not a theoretical number. The unit can actually operate at its minimum, and we're taking the minimum segment, as I've heard you use the term, and allocating that cost to internal load, and it's always there.

Everything above that 300, between that and its maximum, which is 800 megawatts, is available for internal load as well if it's the cheapest incremental cost on the system.

Q. Now, 31 percent of the hours of the four-month period in question the native load of Kentucky Power was less than the minimums of all these -- of all these power plants, correct?

A. No, I don't believe that's correct.

Q. Did you -- you did not rebut that of Mr. Hayet. That's what he testified to repeatedly.

A. I believe Mr. Hayet corrected his own number in his data request to say it was 30 percent, not 31 percent.

Q. Okay. I'm sorry. Thirty point one percent, not 31 percent. So 30.1 percent of the hours of the four months the native load of Kentucky Power was less than the minimum operation of the units; is that correct?

A. I did not check his number. I -- without checking it, I will accept it's probably somewhere in the range of reasonableness.
Q. You would certainly agree that native load customers should not subsidize off-system sales, wouldn't you?
A. I agree with that and I do -- they do not, not under the company's methodology.
MR. KURTZ: Okay. Okay. Thank you, Your Honor.
VICE-CHAIR GARDNER: Thank you.
MR. COOK: No questions.
VICE-CHAIR GARDNER: Mr. Raff.
MR. RAFF: Yes.

CROSS-EXAMINATION

By Mr. Raff:
Q. Good afternoon, Mr. Pearce, or good evening or whatever.
A. Good afternoon.
Q. Let's start with, I guess you heard Mr. Wohnhas's testimony, correct?
A. I did.
Q. Okay. And I believe he stated that he was unaware of no-load costs until a meeting that occurred in November of 2013. You remember him

saying that?
A. Yes.
Q. Were you -- and I think he said that that meeting took place when some folks from the service company came down to Kentucky Power's office. Were you part of that contingent that came down at that time?
A. You know, I came down to their offices down here on or about November-December time frame, so it -- you know, I was in at least one discussion with Mr. Wohnhas on that subject.
Q. Had you been aware prior to that that Mr. Wohnhas was not aware of the allocation of no-load costs to native load customers?
A. I was not aware whether he was familiar with it and to what degree.
Q. Were you familiar with it?
A. With no-load costs? Yes. I've been familiar with it for several years.
Q. Okay. And how did you learn about it?
A. Probably the first time I read PJM Manual 15, a little -- a little bit of light reading, you know, or its predecessor at some point in time several years ago. It's not a topic that came up very -- very often, but yes, I would say I've heard of it

and I was aware of the definition of it.
Q. And was the reason that the topic didn't come up very often because you didn't want people to know about what was being allocated to fuel costs?
A. No. No. Not at all. The no-load costs are, as I actually have on my exhibit, in illustrative fashion, exhibit KDP-2 is basically those costs at the -- at the Y axis, if you will.
The -- you know, we -- the minimum segment, which is basically the no-load cost plus the cost up to minimum, is probably more, I will say internally that we might have talked in terms of. I mean, if you got into a discussion with folks that are on the front lines of our -- doing our bid development at PJM and no-load costs there, you might talk about it more. But no, it's never been anything that we've hid.
You know, this supply curve is a quadratic equation with three coefficients. Basically the A coefficient is the -- that is the -- that is effectively the no-load cost. So you'll see, depending on what group you're talking about -- see, so settlements would call it the A coefficient, prod ops would call it the no-load coefficient. You can get a discussion of minimum load. It kind of

depends on who within AEP you're talking about or, you know, what's the topic of conversation.

But no, we have not ever hid our settlement processes at all. It's -- it was there in the PJM -- our pooling agreement, and we've certainly had ad infinitum discussions about the pool and how it works.

And it kind of came around from the same discussion that, you know, what -- the question that would be asked is, "How do you allocate off-system sales?" And we would go through, "Well, we allocate off-system sales incrementally, top down." That's the discussion that we've been in. And then once we've allocated those costs to off-system, the remaining costs stay with internal.

So you wouldn't explicitly -- just as I think I heard some other utilities say that, "Well, we don't separate out no-load costs." They're kind of in that number if you want to cull them out separate, but you may not have any cause to, you know, explicitly start talking in terms of no-load costs.

Q. Well, I mean, was it surprising to you to learn that Ranie Wohnhas had been with Kentucky Power for 31 years and that he was not aware that the no-load costs were allocated to native load customers?

A. I will say this: I got the opportunity to work with Mr. Wohnhas several years ago. I don't believe he's been with Kentucky Power for that --

Q. I'm sorry.

A. -- for that long.

Q. He started -- he started in 1983, and I guess in 1998 he transferred to APCo, and then the service company as a senior rate consultant. So he worked at the service company for three years as a senior rate consultant and was not aware of the allocation of no-load costs.

A. I don't think that that is any failing on Mr. Wohnhas's part.

I -- as seen in my rebuttal testimony, I worked in rates for -- I've been with the company since '96. I went over to the commercial operations part of the organization in about 2002, and I would say that's when I started coming up to more speed on the front lines. You know, I knew the basics about our settlement systems, how they worked, and then, you know, was there, of course, when we joined PJM in October 2004. So that's how I came about my knowledge of it.

Q. Okay. I think you also heard the question that I asked Mr. Wohnhas about -- or his -- I guess it was his response to his counsel's redirect question regarding the benefits to Kentucky Power ratepayers from owning the Mitchell generating units, and he said that for the months of January through April of 2014 that they received the benefit of $9.9 million in fuel savings that otherwise they would have incurred had they had to buy power on the market, and then I -- you did hear that, correct?
A. I did hear that.
Q. Okay. And then I asked him about the response to Commission Staff's data request, first request, Item 29, Attachment 2, page 1 of 1, which showed the no-load costs. And when I focused on the four months of January through April of Mitchell 1 and 2, that the sum of the no-load costs for the two units for those four months was, I believe, $13.1 million.
A. Yes, I heard that.
Q. Okay. So owning Mitchell allowed the ratepayers to save 9.9 million in purchased power costs while costing them 13.1 million in no-load costs. Is that a fair statement?
A. No. Mr. Raff, I'm sorry, that is not

correct. When I did the analysis of the $9.9 million, just to be clear of the steps I took, actual as occurred, of course, included Mitchell. The estimate without Mitchell is I removed all of Mitchell fuel costs. I took it to zero in the NERs. So that included not only the no-load cost -- so I removed the $13 million for the four months that you're talking plus start-up, plus incremental. Every dollar of fuel cost I took out of the calculation.

Then we analyzed for the four months, okay, but took out the megawatt hours of Mitchell as well and then analyzed, okay, hours with Big Sandy and Rockport as they ran and without the benefit of the pool anymore, how much would they have had to purchase on the market, just pure deficit, to meet their load, and included that cost.

So effectively the $9.9 million is the net of all of the savings that the company had, including the net of basically taking off the $13 million you're asking. And over those four months it works out to be, divided through by internal load, $3.90 per megawatt hour. Estimated value is, I believe, in that paragraph of the stipulation settlement, the 16.75 million. It also makes reference to $2.50 per megawatt hour, which I understand was just somewhat of a crude calculation calculating the difference between Mitchell fuel costs and Big Sandy fuel costs.

But as I show here, we -- 390 of savings well exceeds the $2.50 per megawatt hour that was included in the stipulation. And I will say -- repeat again, that is removing the $13 million that you made reference to.

Q. All right. And I also asked Mr. Wohnhas about the -- two of the KIUC exhibits, Exhibit 1 and Exhibit 8, and those were the original calculation of the cost of Mitchell overlap period, June 2014 -- I'm sorry, January 2014 through June of 2015 and originally as filed in Case 2012-578, then the revised exhibit. And do you know whether the original exhibit includes any no-load costs for Mitchell?

A. To my understanding, having not worked on it, that it does -- it does not include any Mitchell fuel saving -- or, excuse me, Mitchell no-load cost.

Q. Okay. And why would it not include any Mitchell no-load costs?

A. Again, having not really worked on it, that is a number that I understand was -- upon request, was prepared and included, which is this $38 million on it.

I can say this, and I think it's interesting, the numbers that we just talked about, the $13 million of no-load cost, so that's for four months, four months out of 12 on an annualized basis. Three times 13, that's 39 million. That's about the 38.

So if I at least put those -- okay. I said, okay, over four months they would have incurred $13 million of no-load cost if I had put that number in there, but then as I showed in my 9.9 million, I also put in a large portion of purchased power cost savings, which I don't see either in any of these numbers, I mean, what I understand about this.

So perhaps the -- the no-load cost should have been in there, but, you know, what I also don't see is some of the offsetting benefit, at least for the first four months of this year, of dramatic avoided cost savings during the polar vortex.

Q. So basically you're saying there's numerous omissions from this schedule?

A. I'm saying that I've identified two. If you -- that could have been put in there. The one that you pointed out is no-load costs, and my only

point is, that's putting in the cost side as an additional adjustment, but I'm not convinced that there's not also a benefit side to customers that has not been omitted as well.
Q. Were you aware of this exhibit when it was being prepared and presented to the Commission in the Mitchell transfer case?
A. No. I was not on the -- involved with the Mitchell tran -- I attended part of the hearing, but at least part of this I don't recall that I was.
Q. Had you seen this before it was filed?
A. I don't recall.
Q. Did the people who filed it or prepared it, were they aware that they were no-load costs?
A. Well, as we've discussed, I think Mr. Wohnhas stated for himself when he became aware of no-load costs. I won't speak to the others.
Q. Do you know, did Mr. Wohnhas prepare this exhibit by himself?
A. No. I don't know who else might have helped him. You know, I do know that Mr. Allen is up, and he was also involved in the settlement, so he may have some additional questions. He was more directly involved than I am.
I will say this, you know, having developed

various estimates, when you're trying to get a precise -- you know, sometimes as far as every component that you, you know, put in or didn't put in, I don't -- I just don't know. I haven't -- I haven't done a thorough analysis to identify what else should or should not be in this or, you know, that would rise to the level to include it.

Q. Could you refer to Kentucky Power's response to the Commission Staff's second request for information, Item 4 c. and Attachment 3 to that response?

COMMISSIONER BREATHITT: Item 4?

MR. RAFF: 4 c., and there's an Attachment Number 3 to the response.

Q. Staff had requested Kentucky Power to provide the amount of no-load costs that would have been allocated to internal load customers if no-load costs had followed the allocation of all other fuel costs when calculating the FAC. And Attachment 3 provides that amount by months.

My question is: Do the amounts in Attachment 3 reflect only no-load costs being allocated or do they also reflect the allocation of the other incremental costs between the no-load costs and the unit minimums?

A. Give me just one second here, please. The way we read the data request, which was, "Refer to the response to Item 29.e. Provide the amount, by month, that would have been allocated to internal-load customers if 'no load costs' had followed allocation of all other fuel costs."

So at least the way that we interpreted the request was to show if you did this, which I think in our response -- let me -- let me double-check that.

Yes. So at -- based on the request, we wanted to be responsive, so we interpreted it to say what if we had allocated the no-load costs on this basis. As we said in our narrative response to the question, we said, (Reading) The allocation illustrated in KPCS 2-4 Attachment 3 is neither reasonable nor appropriate.

And I -- and I agree with that. But we provided the number based on our interpretation of the data request response.

Q. I'm sorry. So it just reflects the no-load costs?

A. Yes.

Q. Okay. Could you provide an update to that Attachment 3 that reflects both the allocation of the no-load costs and the other incremental costs between no-load costs and unit minimums?

A. Okay. Just so I can understand your request, are you asking if we had maintained our current method for allocation of incremental cost? So basically you want to see what the number would be on off-system sales if we loaded it up with not only the most expensive incremental costs, but on top of that we had also allocated to follow those more expensive dollars additional no-load cost? We could certainly provide that if that's the request. We disagree with it --

Q. It is.

A. -- clearly, but we can provide that set of numbers --

Q. Yes.

A. -- I would believe.

Q. That's the request.

A. And just so I can add to that, you know, the reason that we feel it's inappropriate, as shown in my exhibit, in Exhibit KDP-2 -- again, this is just the illustrative supply curve. You know, ideally what we want to happen is this, and we hope it happens in every hour, that we dispatch our supply curve out to satisfy our internal load through the cheapest sources, yes, including the no-load cost, and then we continue to dispatch out to make some additional off-system sales.

Clearly in a given hour the off-system sales margins can be very thin. So as I state in my rebuttal testimony, our concern continues to be that if you start allocating no-load cost onto off-system sales margins that, you know, with luck, at times, barely cover your incremental costs, then what you're turning is off-system sales margins from a -- you know, what was -- what was an economically sound sale to make -- even if the margin was small, it gave you some contribution to your fixed costs under our traditional sharing mechanism. Customers would have benefited from that sharing -- to basically turning some positive off-system sales into negative sales when you allocate costs in that method.

Q. Would you agree that Kentucky Power would not be able to make off-system sales if it did not incur the no-load costs?

A. To have a unit on, it is incurring no-load cost. If we have dispatched our units first and foremost for our internal load customers, then on an incremental basis we are not incurring any additional cost to make that additional off-system sale. So on an incremental basis there is no more no-load cost than we would have incurred otherwise. Yes, operationally the units are producing or are incurring no-load costs whenever they're online.

Q. Okay. So any hour that the unit is not being used to serve native load, it's still incurring no-load costs, native load is paying for that, and the company is able to make off-system sales?

A. No. Again, from our method, every unit that's online in every hour, we are allocating some of that unit to our internal load. We don't have the situation where we have units online but all of the output is going to an off-system sale, we are allocating up to the minimums to internal load, and then between the dispatchable limits, we will assign the most expensive incremental generation to the off-system sales. So they are paying the most expensive incremental costs for the --

Q. Well, aren't there --

A. -- off-system sale, and internal load gets the benefit of the cheaper incremental cost plus the cost of the unit minimums.

Q. Aren't there many, many hours where all of Kentucky Power's units are not needed to meet its load?

A. Under a strict definition of saying I can look back in hindsight and I can see what was running and I had this many megawatts of generation and then I had this many megawatts of load, and I'm looking backwards, and say, "Oh, it didn't need this unit in this hour, so, you know, don't allocate any of it to internal load."

What I find interesting, and it's reflective of the KIUC method, is -- and this is part of my testimony, is, you know, it's basically -- talk about theoretical. It's making a presumption that you could turn the units on and off like light switches by the hour. It's saying in hours ending two, three, and four, like in the middle of the night, "Well, load's down, we didn't need that unit. You take it to off-system sales. Good luck. Hopefully you'll get all your costs," at times, if we're barely incurring our incremental costs, "but during the daytime, you know, we need it for two hours for internal load, so we'll take some of it." Okay. Then after that, "Well, we don't need it anymore, so you allocate it back to off-system."

And in any given hour we are not recovering necessarily the incremental cost plus some sort of allocation of our no-load cost. And that's an important point. The way that PJM does their dispatch is we offer the units in, basically with a minimum run time of 24 hours. So they -- if they select your unit for a next-day award, they will basically make sure that over the 24 hours that you're made whole. But hour by hour, you know, what they're doing is -- that's why they have you -- as I showed in my testimony, you -- they make you provide your no-load cost and then your incremental block cost.

And so they'll say, well, in a given hour, even if you're barely recovering your incremental cost, but in the daytime, during the peak hours, you're recovering more than that, you're recovering your incremental cost plus a margin, enough to cover your no-load cost, so for the whole 24-hour period you're made whole.

Where that runs into trouble for us is if -- you know, if that's -- if you said that's kind of a merchant gen look. We're a regulated utility --

Q. I'm sorry. That's what?

A. That's kind of -- if you said that's kind of a merchant gen look. You could say, okay, the unit is made whole for the whole 24 hours, but from our perspective as a regulated utility, our units are there first for internal load. So from hours two to six in the morning, again, we're barely covering the incremental cost, and the LMP is not reimbursing us for any no-load cost. Okay?

A merchant gen would say, "That's okay, because during the peak hours prices shoot up, I make good money and I'm covered for the loss in the off-peak." From our perspective, during the daytime hours is when the Kentucky Power's load goes up as well, so we don't have the opportunity to kind of make back our losses during the off-peak in the middle of the night because we're serving our native load customers. And that's why we think it's appropriate to model what the dispatch does. Don't select that, "Well, from hour one, two, three, four, I'll take the unit this hour, then I won't the next hour, then I'll take the unit the next hour, then I'll take -- then I won't take the unit the next hour."

We recognize the dispatch, that the units come on with minimum start times, minimum run times. We allocate the minimums and then we look at the incremental dispatch between the minimum and maximum, because certainly for any unit -- when Big Sandy is somewhere between 300 and 800 megawatts, if we dispatched it any above 300, we had to have a reason we're doing that. It was either to serve more internal load or it was to make off-system sales. So if Big Sandy 2 was the most expensive incremental unit for that fifth hundred megawatt, that's what we assigned off-system, because we'll say but for that off-system, it wouldn't have produced 500, it would have only produced 499 megawatts.

But all of that no-load cost, all of it up to that minimum segment of 300 would have been borne by the customers either way. And we think that's long term the best for our customers, because again, under a normal, traditional sharing of off-system sales we're asking them to pick up the base load cost of the units when they're online, we maximize the off-system sales opportunities and off-system sales and we share it equitably with customers.

And this is what I mean by really the cost allocation should follow the dispatch. That is -- that's been drilled into me for -- since I've been involved with this by people that worked for the company long before I started

Q. But the cost allocation doesn't have to follow the dispatch, does it?

A. See, that's what -- I believe it very much so has to. I mean, I'm a believer in cross causation as well, and I want my customers to -- basically they incur the cost but that -- that is due to them. If I am incurring costs that's making an incremental off-system sale, then that's the cost I allocate, and then I share the profit of that back with my retail customers to provide them the most benefit of that.

If I start having to load up in my day-ahead offers into PJM to say, well, now I know, even in the middle of the night, you know, I have to -- I have to basically require that at 3:00 o'clock in the morning I need enough margin from my sales to not only cover incremental costs but also some allocation of the no-load cost rather than say up to the minimum the internal load will save it, then that would basically cause me to offer in my units at a higher cost, and maybe they don't get picked up as much. And I think that's harmful for customers. I want to -- I want to optimize my units in the PJM market. I think that's the best deal for customers long term.

Q. In the same data response that we were earlier referring to, the response to the Commission

Staff's first data request, Item 29, but at page 4 of 4 of that response.

A. Item 29. I'm sorry, which -- and then which?

Q. Page 4 of 4.

A. Yes, sir.

Q. Paragraph e, the statement, "Economic dispatch does not result in an allocation of "no-load costs."

Do you agree with that?

A. Yes.

MR. RAFF: Okay. Thank you. I have no further questions.

EXAMINATION

By Vice-Chair Gardner:

Q. Dr. Pearce, I have a couple questions, please. First, did you submit any testimony or answer any data requests in the Mitchell case?

A. I did not submit any testimony. I was not a witness in that case. Regarding data requests, I don't recall if I reviewed any or not.

Q. Did --

VICE-CHAIR GARDNER: If you -- if you could show him KIUC Number 8, please.

MR. GISH: Mr. Vice-Chair, I believe he has it on the stand.

VICE-CHAIR GARDNER: Okay.
THE WITNESS: Oh, do I?
Q. So I'm asking you about page 3, which is the rate change comparison, page 3, the 5.33 percent in there.
A. Oh, I'm sorry. Yes, this page. Yes, I have that. Yes.
Q. Do you recall seeing that at the time before it was submitted?
A. Honestly, I don't recall whether I did or did not.
Q. Would you have noticed that it didn't appear to include no-load costs in that?
A. You know, I don't know if it would, because honestly I don't recall at the time, like if -- you know, if the Mitchell fuel savings calculation had been done on something sort of more complex, you know, that it may or may not have included that. So I might have, you know, inferred that that calculation was -- somehow had that factored into it, I just don't know.
It was only -- I think it was sometime later that I, you know, understood that the calculation was based on just kind of a historical difference between the fuel cost of Mitchell versus the fuel

cost of Big Sandy 2, which is valid. I mean, as I think the company and Mr. Wohnhas showed, it's going to be 89 percent. Customers are again going to get the benefit, at least long term, of lower costs in their -- in their retail load or some traditional sharing under off-system sales.

Q. So you believe that this is incomplete and that the Commission should not have relied on it because it doesn't have all the information in it?

A. I cannot -- I cannot say that.

Q. Is this complete?

A. Is this complete? I don't know in the context in which it was provided. I -- and I apologize, Vice-Chairman. I'm really not trying to avoid the question, I just really don't know. Again, since I didn't know, like, the Mitchell fuel savings, how that was calculated --

Q. I'm asking -- yeah, I'm asking you in retrospect.

A. In retrospect?

Q. Is this incomplete?

A. I don't know. And the reason I say that is because if there had been --

Q. Should there have at least been a mention of no-load costs in here, at least in a footnote? Like it does not include it or no-load costs are additional or --

A. You know, if I had been more involved and we had done some more complex modeling, you know, maybe there would have been additional line items, but with that said, I think -- and I understand where folks were coming from AEP in the sense that our cost allocation method was nothing that we were intending on changing. It was the same as it always was, so I kind of understand from the standpoint that they put in a basic, it's two fifty dollars' difference in cost between the plants.

And as I had stated earlier to Mr. Raff, if I did accept that, the L -- maybe we should have had a line item in here for no-load costs. I haven't gone through it to identify, but perhaps there's additional off -- savings that would have offset that.

Q. And how could -- how could you say that, you know, that should have been put in here when you heard Mr. Wohnhas saying he didn't even know about the existence of it at that time?

A. I'm sorry?

Q. I mean, you said that you know that -- you know that you're doing nothing different with

no-load costs than what you had always done.
A. I understand.
Q. So how can you tell that no-load costs are included in here?
A. How can I --
Q. How can you tell?
A. Oh, and to the extent that the no-load impact on this exhibit is not in here, I agree with that.
Q. Okay. Let -- I do have one other question. Your testimony is basically that you-all have this excess generation during this period and in -- and that you're going to -- are you going to run it all the time? It's going to be available all the time unless it's taken off-line for servicing?
A. Well, because, you know, being a member of PJM, we're required -- anything that's been designated as a PJM resource we have to offer in on a daily basis.
Q. Okay.
A. We're -- so it -- the units will run per PJM instruction, if they're available to run.
Q. Okay. So -- okay. So they -- they're required to offer those or at least have them available, therefore, as we're sitting here right now, these units are incurring no-load costs?

A. To the extent that they're on.
Q. If they're on?
A. Yeah. I think Big Sandy -- both units may be out today.
Q. Okay.
A. And again, this is -- kind of reinforces --
Q. But in general this is --
A. Yeah.
Q. -- this is going forward because they have to offer them unless they're out for maintenance or whatever?
A. Yeah.
Q. And they have gotta offer them into PJM and these no-load costs are being incurred as we're sitting here, theoretically?
A. Yes.
Q. Okay. Now -- so when this settlement was constructed that had these four -- that had these extra units in there, that automatically, from -- someone who understood no-load costs would know that that meant that from day one there's going to be -- as long as they're in service, that there's going to be no-load costs that are going to be incurred by the ratepayers whether they're offered into -- whether they're taken, whether there's off-system

sales or not, is that correct? I mean, the sales are sort of irrelevant. The costs are going to be there all the time.

A. Yes. The costs are -- well, with -- the no-load costs are incurred to the internal load as far as the off-system sale. The level of -- as you have the off-system sales, certainly you're allocating costs away from internal load to off-system, and they are incurring the remainder.

Q. Okay. So what is the benefit to the ratepayers for the off-system sales component of this? How do ratepayers -- I mean, I heard -- so the units are going to have to be offered into PJM if they're -- if they're not out of line -- out of -- or in service, and they are going to incur those costs, and I understood you talking about the benefits of that, which the benefits to the ratepayer is that it means that they can -- I mean, if something happens, if we've got a polar vortex, they're available, they're ready, and that -- there's some value to the ratepayers for that.

Is there a value to the ratepayers for off-system sales occurring beyond the 15 million that are in base rates? Is there any benefit at all to the ratepayers for that piece of it? I mean, a

hundred percent --
A. Well, okay. With -- and as you -- as you've already acknowledged, the fact that we've provided a hedge and the fact that they have all six units available. So you've already mentioned that.
Beyond that, as far as off-system sales, during this interim period that we're in where we recognize that we're getting the benefit of a good unit in Mitchell, and in exchange for only providing, I think, $44 million, there was the recognized opportunity that the company would receive the off-system sales.
So to answer your question, I don't see additional benefit to customers during this period from the off-system sales. It is certainly allocating costs, you know, that they don't pick up from the units operating, but that's only fair. The -- when we get past this period --
Q. But while we're in the hundred percent time period, which is at least until May of -- not at least, it's until May of 2015, there's no -- the ratepayers get no benefit beyond the 15 million because a hundred percent of the off-system revenues are going to Kentucky Power?
A. They get no benefit other than the hedge

benefits that --
Q. Which I've already --
A. -- that you had mentioned. And then again --
Q. But that doesn't matter whether there's off-system sales or not. They're getting the hedge benefit because they've gotta have the units ready, right?
A. That's right.
Q. Okay.
A. That's right.
Q. So there's no additional benefit to them if there are sales that are made or not?
A. There is no benefit to them, not -- not from the incremental sales. I'll agree with that. Now, having the units all on, I mean the units that are available and on, provides, I'll say, the immediate benefit, because again, we go back after the fact and see which units had the most expensive incremental costs, assign that to internal and keep the cheapest with the -- or, excuse me, assign that to off-system and keep the reminder with our internal load customers.

So I do see the benefit of, you know, yeah, something could happen, but, I mean, even in real time is my point there, by them incurring the no-load cost and the unit is up and running, because that relative to a scenario where we just shut a unit down. I also have in my testimony the start times of the units, which is very significant. So if we have an event, a unit --

Q. But --

A. -- goes out or a forecast --

Q. But I'm just trying to understand the --

A. I understand.

Q. -- the off-system sales piece of it alone. I mean, I understand because you say that the -- and I hear your point about the no-load -- because of the no-load costs --

A. Right.

Q. -- the rate -- the ratepayers get a benefit, and I understand that.

A. Okay.

Q. Are they getting any benefit from the off-system sales?

A. They're not getting any benefit of the margin from the off-system --

Q. Okay.

A. -- sale per the settlement.

Q. Okay. And I just wanted to make sure because you say several times about the -- in your testimony about the ratepayers getting benefits, and I just wanted to make sure --

A. Sure. I understand.

Q. -- that I was understanding that there's not some other benefit that I'm missing.

A. I understand. That's fair.

Q. Okay.

A. And I -- you know, one -- I kind of came into this and noticed this -- the stipulation and settlement, I couldn't help but note paragraph 15 that talks about, you know, Mitchell on top of everything else being dispatched in an economic dispatch order, which seems to validate, the way I read it in paragraph 15, that it would basically support that we're going to put Mitchell into the stack just like all of the other units. With the pool gone, Kentucky doesn't have that to lean on, so they are going to get the benefit of Mitchell, and they get the benefit of Big Sandy too, hopefully, knock on wood, until next May. We'll see what happens.

VICE-CHAIR GARDNER: Thank you.

THE WITNESS: Thank you.

MR. GISH: Just one --

VICE-CHAIR GARDNER: Yeah.

MR. GISH: One or two brief redirect questions.

REDIRECT EXAMINATION

By Mr. Gish:

Q. Dr. Pearce, you testified about this 9.9 million in net savings to the customers, and that means that there are 23 million, approximately, dollars in avoided market costs during the four months?

A. Yeah. I mean, it was -- you know, our analysis was a little more complex in terms of we included additional purchases that they would need, and then we also curtailed off-system sales in terms of, okay, in other words, you didn't have surplus out of the other units. So all of it together netted to a -- but definitely factoring in the exclusion of the no-load costs came out to be $9.9 million.

Q. And that's a calculation of this hedge benefit that the Vice-Chairman was discussing?

A. Well, I mean, that's the actual benefit in cost savings. The hedge value, I would say it's like an option on a stock or anything else, which normally you have to pay for, so in a sense they've -- you know, the customers have benefited by

$9.9 million and got the hedge or the option for free over this period, because they always had it available.

Q. And just one more question about this hedge. If you -- if the company has all six units available to run, will bid all six units available --

A. Uh-huh.

Q. -- to run into PJM, if those all six units are picked up by PJM, that means that the costs of running those units is less than the market cost; is that correct?

A. That's the important point. When PJM picks them up, the costs of the -- running those units is less than the market cost over the entire run time.

But that goes to my point. They're not going to necessarily make you whole hour by hour. And that's part of the fallacy I see with the KIUC proposed method is that basically it's a very cherry picking of, you know, taking a unit this hour, then not this hour, this hour. Well, recognizing if I brought the unit on, I assume PJM is doing the dispatch, it's there first and foremost for internal load. To the extent I have some dispatch above the minimums, that's where I'm assigning the most expensive cost to my off-system.

Q. And earlier today Mr. Kurtz asked you some questions about the difference in the results of the method that LG&E and KU use to calculate their -- or sorry. I'm sorry. To allocate their fuel cost to off-system sales. That methodology is for large -- for the -- their coal-based units is the -- or coal-fired units is the same methodology that Kentucky Power uses; is that correct?

A. I see -- I see very few differences.

Q. Yeah. Do you think it's appropriate for the Commission or for -- or any Commission to say one methodology is correct if it results in -- if the application of it is a little lower and say that the other application -- say one company's application of the same methodology is okay and one -- and another company's application of the same methodology is not okay?

A. No. The numbers should not drive the -- I mean, if something is correct to do -- I'm an engineer, of course I want the methodology to be as correct as possible.

Q. And so it's -- so it's better and more appropriate for it to be a uniform methodology?

A. I believe, you know, it's -- I mean, it makes sense to me. I believe there's even something --

and I'm not an expert in KIUC discussions on that matter, but yeah, I think it's -- it makes sense to me.

Q. And you mean LG&E and KU, not KIUC; is that correct?

A. I'm sorry. LG&E, KU, AEP, Kentucky Power.

MR. GISH: That's all I have, Vice-Chair.

VICE-CHAIR GARDNER: Mr. Kurtz.

MR. KURTZ: I do have a little bit.

RECROSS-EXAMINATION

By Mr. Kurtz:

Q. You referred to the KIUC fuel cost allocation method; is that correct?

A. Yes.

Q. Do you -- you recognize that what the Attorney General and KIUC are recommending for fuel adjustment purposes is the exact same fuel allocation method used by East Kentucky Power Cooperative and Duke Energy Kentucky?

A. I will dispute that as far as -- in terms of it being the exact same as East Kentucky Power Cooperative. I have not analyzed the East Kentucky Power Cooperative method other than the testimony that your witnesses have provided in exhibits. But what I read in the testimony of Mr. Hayet is that he is doing a bottom-up, assigning costs to internal load first, and then whatever's left over is off-system sales.

What I saw in your same Exhibit 4, I believe, which was the response by East Kentucky Power Cooperative, they mentioned that they were doing a top-down allocation method, is the way I read it.

So that's at least one difference. So I haven't analyzed the East Kentucky method in depth, but it seems -- certainly seems that there was a contradiction between East Kentucky's response to that data request and what -- and what KIUC is proposing.

Q. Well, is this the same difference, like a 31 percent situation of native load not meeting the minimum, the answer is 30.1 percent? I mean, you understand from the testimony of Mr. Kollen and Mr. Hayet that they tried to replicate, and did, the East Kentucky and Duke methodology, and you did not rebut that in your written testimony, did you?

A. I did not state it because, as I'm stating -- what you just asked me is do I understand they're the same, and my answer back to you, I didn't confirm it in my rebuttal or deny it because I haven't looked at it enough. I'm just saying from the testimony you filed, there's an inconsistency there, and I can't speak to that coupled with other things, whether that would drive a very small difference or a large difference. I don't know.

I can give you an example. If East Kentucky is doing top-down, I -- you know, one way or the other you have to tie to the books. You incurred a couple -- a certain amount of expense, fuel expense. You're measuring the weight of the fuel on conveyor belts to the plants. This is what's hitting your general ledger. So one way or the other you're going to allocate costs off-system and then what's left is internal or you're going to allocate costs internal or then what's left over is off-system.

If East Kentucky is working its way down, which is what I read from their data request response, then something like start-up costs, okay -- if they're only allocating costs to off-system hours that the units actually had megawatts of output to off-system, then they're not allocating any start-up costs to off-system sales. Okay?

What I read -- what I -- and I know the KIUC somewhat better, because I looked at least at your work papers. The KIUC, going top-up -- bottom-up, they would only allocate cost to internal load for hours that the units actually had megawatt hours of in -- of output.

So any coal unit, there's going to be hours that you're burning coal, your start-up coal -- well, your fuel oil, whatever you're doing for your fuel, to bring the unit up to -- up to speed, up to synchronous operation. And, you know, from that method, it looks like they were basically forcing all the start-up costs of the units to off-system sales as well in their $12.6 million number.

So I think there's more -- that's the way I understood it, but it looked like -- so it looks like there's potentially some differences, certainly going from top -- top-down or bottom-up, there can be some differences.

Q. Now, are you speculating about the start-up cost issue? Because you certainly didn't testify to it.

A. I'm spec -- I'm -- what I'm stating is, I did not see it in Mr. -- since you asked me if I understood that they were the same, and what I'm -- so I'm answering the question is, they didn't look the same to me. I gave an example from what I saw in the work papers of a difference, and -- you know, as far as start-up costs. What I could see is in KIUC's method allocating it all to off-system sales. And I'll just state, I am -- I am skeptical but I don't know if East Kentucky forces all of its start-up costs to its off-system sales. I doubt that.

Q. Do you have your Exhibit 5 in front of you? This is your $9.9 million savings exhibit. Do you have that?

A. Yes.

Q. Okay. Do you also have KIUC Exhibit Number 2, or can you be provided that?

MR. GISH: Which one is KIUC 2?

A. I'm sorry, I'm not sure.

MR. KURTZ: It's the Staff 1-29 exhibit, page -- Attachment 1.

A. I got it.

Q. Okay. All right. Do you see in the right -- KIUC Number 2, the bottom right-hand corner, the fuel cost allocated to native load. Let's just -- let's just use the munch of -- the month of March. Do you see that, where it starts with allocation of native load fuel cost 5.516.03 million from Big Sandy 1, et cetera?

A. Okay.

Q. Okay. When I add up those columns, I get 17.755 million, versus your Exhibit 5 is 18 million. Why is there the quarter-million dollar discrepancy? Or please check my math.

A. Okay. I -- to save time, I'll -- it's -- I won't check your math, but one difference is actuals incurred is the actual NER, so it includes purchases.

I don't see in this KIUC 2, 14, 220, or whatever, if I've got the right reference. This is just strictly the units. It doesn't include the cost of purchases.

Q. Okay. And your exhibit includes the cost of purchases?

A. Yes.

Q. Okay. Now, as I understood your exhibit, what you said, for March of 2014, if you replace the Mitchell megawatt hours with market purchases, it would have cost Kentucky Power ratepayers $6.3 million more; is that correct?

A. Yes.

Q. Okay. So the Mitchell megawatt hours for March of 2014 were 277,070 megawatt hours, and we see the megawatt hours for Mitchell on the left-hand side of the column. Do you see that?

A. Mitchell for March. You're saying the hundred seven five five? Is that the number you're looking at? And the 176315?
Q. Yes.
A. Okay.
Q. They add up to 277,000 megawatt hours.
A. Okay.
Q. If I divide that by the $6.3 million presumed savings, that would mean that you would be purchasing for $22.70 a megawatt hour more than what Mitchell was generating at. Did I do that math correctly?
A. Okay.
Q. Is that correct?
A. Yes.
Q. Okay.
A. Something like that.
Q. And Mitchell generation costs for the month was $29.49 a megawatt hour; is that correct?
A. Something in that range.
Q. So your exhibit shows that if Kentucky Power didn't have Mitchell, they would have bought market purchases for $52.23 a megawatt hour, because they would have bought -- instead of buying Mitchell for 29.49, they would have paid $22.70 a megawatt hour

more and bought market power for $52.23 a megawatt hour?
A. The calculation is a little bit more complex than that, but if you want to talk in general terms.
Q. Is that right, general terms? Because you're replacing the Mitchell generation with market purchases, you say you save 6.3 million. That comes out to a market purchase of $52.23 a megawatt hour.
A. We didn't replace all of the Mitchell generation with market purchases. What we did is remove all of the Mitchell generation and all of the cost, and then we only made additional purchases for hours that the company was going to be short.
Q. Oh.
A. Which could be in the most peak hours.
Q. Oh. Well, because in that same month Kentucky Power was selling off-system from Big Sandy 1, Big Sandy 2, Rockport 2, Rockport 1, 245,986 megawatt hours.
Why would Kentucky Power be purchasing $52 power when they had access to $30 power from their own generation?
A. That's part of the calculation. What we did was, they bought purchases when they -- first step, we took it all out. Second step, we basically said

for hours that all of the generation running, including both Big Sandy 1 and 2 and Rockport 1 and 2 were available, we netted that against internal load. And we said if there's nothing else for them to take, then we bought purchases. But we reduced those off-system sales, those other units.

So yeah, that dollar amount includes both those effects. That's why it makes it more -- a little complex. It's a combination of replacing the Mitchell costs with purchases and with instead being supplied by Big Sandy and Rockport. And then we reduced also the volume of off-system sales, obviously --

Q. Well, what are you --

A. -- so they made more purchases --

Q. What did you --

A. -- and they made less off-system sales.

Q. Well, there's no work paper. This was presented a week ago. There was no work papers, no backup. What purchase price did you assume Kentucky Power would have to pay in the market if it didn't have Mitchell?

A. That's a fair question. We did -- we looked hourly, and for every hour we did -- it's an hourly calculation for that -- for that portion of this.

And this is an estimate, but for every hour, we just -- it's kind of back to our earlier discussion, is that if in this -- because purchases you can buy on and off, it's units that you can't turn on and off by the hour.

But purchases, we just said if their load was a thousand, and when they had 800 megawatts of Mitchell, their generation was 1,600, so they were surplus, they wouldn't need to purchase. If I take out 800 megawatts of Mitchell, then they go to having to buy 200 megawatts of a purchase, and, of course, they make no off-system sales then in that hour, so --

Q. Why did you --

A. -- that was the calculation, and so the purchase price, to answer your question, is driven by the hours they made the purchase, and not surprising, the hours they're going to be short are generally going to be the peak, more expensive hours.

Q. What was the average purchase price in your calculation for the month of March, or for the month of April, for that matter?

A. I don't recall it off the top of my head. I want to say it was -- I mean, it was obviously -- I think you quoted 50. I think that's rational, because again, they only made purchases for the hours that, absent Mitchell 2, and with getting basically whatever other resources they could, they still didn't have enough to cover, so they bought at that hourly LMP.

Q. Well, then you did assume that none of the extra power they would -- Kentucky Power would need would come from Big Sandy 1, Big Sandy 2, Rockport 1, or Rockport 2?

A. No. I'm sorry. Let me -- let me give you a better example. If the load was 1,000 and they made -- they produced 1,800 megawatts hour -- 1,800, of which 600 was Mitchell and 200 was from Big Sandy, okay, when I -- well, that's not a good example, because then they still would have made something.

But the point is, is if they made -- if the load was 1,000, 1,600 was the gen, I take out -- and that 1,600 of gen was some combination of Mitchell and Big Sandy, when I remove all of Mitchell, I don't still assume that Big Sandy was able to sell. I apply Big Sandy to the deficit.

So I reduced the volume of their off-system sales. And then if -- basically if I took off-system sales to zero, so they got -- they got every bit for internal load, which we always do, of Big Sandy and Rockport and they still needed a purchase just to become even, that's when we applied purchases.

Q. Yeah. Well, then the purchase price would have had to have been a lot higher than $52 a megawatt hour?

A. And it wouldn't surprise me if it was. Again, you're talking about the hours that they needed it was generally going to be when the load was pretty healthy, and it was -- we're talking about March.

Q. Right. March and April.

A. Well, we were talking about March.

Q. Well, true.

A. Okay.

Q. Now, why -- this is -- this is your estimate.

A. Yeah.

Q. That's what it -- that's what this exhibit is called, right?

A. Uh-huh.

MR. KURTZ: Okay. Thank you, Your Honor. No more questions.

MR. RAFF: Can we have one second?

RECROSS-EXAMINATION

By Mr. Raff:

Q. Maybe just one question, or two. You work for the AEP Service Corp., correct?

A. Yes, sir.

Q. Okay. And they provide services to all of the operating companies, or at least the east operating companies?

A. All the -- all the operating companies.

Q. Okay. At least for the east, what is known as the east, they have companies operate in West Virginia, Virginia, Michigan, Ohio, Indiana, correct?

A. Yes.

Q. Excluding Tennessee. To your knowledge, are the other regulatory commissions in those states aware of the way in which the no-load costs are allocated a hundred percent to native load customers?

A. I don't know. I can't comment.

Q. So you've never had occasion to testify in those other jurisdictions on this issue?

A. Not testified. I could say a few years back -- again, as far as not hiding anything, the Indiana Commission had an interest in our pool, so again, my quarterly class pool school, I went over into Indianapolis and gave a presentation to the Indiana Commission, the Chairman. It was an informal conference, so the consumer advocate, anybody who wanted to -- I've been perfectly happy to put anybody to sleep that wants to hear for a few hours about AEP settlement.

Q. So it's your recollection that you explicitly discussed the fact that the no-load costs are put a hundred percent onto native load?

A. I don't know that we got into specific no-load costs. What I do know is I have a -- actually, it was kind of déjà vu, because, because of this case, when I saw the LG&E/KU presentation, and they had like a box stack and they're talking about how they allocate things, I have actually, and it's purely coincidence, a similar drawing in my own where I talk about how we allocate the most expensive resources to off-system, and then, you know, how the -- how, after we have allocated the most expensive resources to off-system, what remains is for internal load across the companies, and there's primary payments and everything. I don't recall, I mean, again, specifically getting into no-load costs.

Q. Well, when you say you allocate the most expensive resource to off-system, that's after native load pays for the no-load cost, right?

A. No. Well, again, we've always done top-down. We allocate -- whether it was before the pool or now, we would allocate the most expensive incremental resources -- I think I have in my testimony an example of saying if, you know, a given unit is 400 megawatts at 11,000 of fuel cost, our supply curve would say if I sold so much as one megawatt hour, then it would have only dispatched 399 at $27 less than that. So that's that $27 incremental cost we would allocate to off-system. And I do believe that I've been clear about saying we look across all the units. And in the PJM pool, you're literally looking across dozens of units, identifying the most expensive dollar per megawatt hour cost across dozens of units, finding the most expensive one that was dispatched, and that's the one you're assigning to your off-system sales. And, of course, Kentucky Power got a similar share of that --

Q. Isn't that --

A. -- both the revenue and the cost.

Q. But isn't that after the no-load costs are allocated to native load customers?

A. It -- the native load customers have always got the no-load costs, I agree with you. I -- the only thing part I'm struggling is you say "after," and again, even then we were doing top-down, so I would say the first step is allocate to off-system and then subsequently is when the no-load and the remaining cost stays with internal load.

But yes, they pay no-load costs, it's just we don't do it bottom-up, we do it -- we still did it top-down, the same we're doing it for Kentucky today.

Q. Does it result in the same number?

A. If you designed it the right way, it -- if you designed it the right way, you could make it get there.

MR. RAFF: Okay. Thank you. No other questions.

THE WITNESS: Thank you.

* * *

EXAMINATION

By Commissioner Breathitt:

Q. Dr. Pearce, you were talking with KIUC counsel, and I heard you choose an interesting word. You said, I think -- it had to do with Duke and East

Kentucky, I believe, and you said they forced costs onto off-system sales. Do you recall -- is that what you said, you force -- that they forced their costs -- why -- what's the import of -- importance of using the word "forced"?

A. The -- I think, if I recall the con -- the context I was using that word is, is in this scenario that I discussed about particularly during the summer months, again, if you -- if it's going to be a hot day, if the air is dry, it can really cool off at night, you can have low load conditions. So I looked over the -- just the six months of this period, it didn't include a summer, the average LMP for like the 20 percentile, so the lowest 20, was only 27.50. You know, it got down into the teens. The real-time price is actually -- there was one hour it went negative. You had to pay power to put it on the grid. So those are hours nobody is trying to make off-system sales. What you're doing is by saying I'm keeping the unit on for the benefit of my customers to serve them during the next day's peak.

So my -- my issue with the -- with the KIUC type method is to say -- you know, to say that in certain hours when it -- you know, I'm just going to take a very narrow view of here's my internal load, here's my generation, the specific hours of 2:00 to 4:00 in the morning I don't need it from that calculation, so you go make your money in the off-system sale market, when you're not really making money in the off-system sales market. What you're doing is you're trying to keep the unit on for the next day's peek for your internal customer.

So I -- to me that's -- that -- that's -- you know, and so if you're doing that with just your incremental costs, to kind of add insult to injury and say, well, now we want you to load up a lot of your no-load costs on that as well, then it's -- it misaligns the interest of the company and the customers. I feel like today those interests are aligned.

Q. Wouldn't it be their choice? I mean, it wouldn't -- they wouldn't be forcing themselves to do that, it would be their choice.

A. And that's true as far as the company's choice. If -- that's what I mean by misalignment is, is if the company knows that, hey, anytime I'm going to make an off-system sale, I need to get all my money back, so if they're going to start basically having to allocate some no-load costs to their incremental cost offers in PJM, then there's chances that PJM won't pick the unit up, won't dispatch the unit.

So yeah, it's not there in the off-peak, you know, when that's fine, 'cause maybe, you know, the market's about the same price and customers are not harmed, but that also means then the unit is not there in the next day's on-peak because of the turnaround time, the minimum shutdown time of the unit and the minimum start-up time of the unit and all the extra cost that goes in with cycling a base load unit.

COMMISSIONER BREATHITT: Okay. Thank you.

VICE-CHAIR GARDNER: Mr. Gish.

MR. GISH: I have nothing further.

VICE-CHAIR GARDNER: Anybody else?

Okay. You're free to go. Thank you, sir.

THE WITNESS: Thank you.

COMMISSIONER BREATHITT: Do you-all want to take a break or do you want to keep going?

VICE-CHAIR GARDNER: We can keep going, right?

Okay. We'll take a seven-minute break, come back at 7:30.

(Recess from 7:22 p.m. to 7:34 p.m.)

VICE-CHAIRMAN GARDNER: Back on the record.

And, Mr. Allen, if you would stand and raise your right hand, please.

* * *

WILLIAM A. ALLEN, called by Kentucky Power Company having been first duly sworn, testified as follows:

VICE-CHAIRMAN GARDNER: Please have a seat. State your full name.

THE WITNESS: My name is William A. Allen.

VICE-CHAIRMAN GARDNER: With whom are you employed?

THE WITNESS: I'm employed by American Electric Power Service Corporation as managing director of regulatory case management.

VICE-CHAIRMAN GARDNER: You may ask.

MR. OVERSTREET: Mr. Vice-Chairman, Mr. Gish is going to present.

VICE-CHAIRMAN GARDNER: Mr. Gish.

MR. GISH: Thank you, Vice-Chairman.

DIRECT EXAMINATION

By Mr. Gish:

Q. Mr. Allen, did you cause rebuttal testimony to be filed in this case?

A. Yes, I did.

Q. And do you have any corrections or changes to

make to that rebuttal testimony?
A. No, I do not.
Q. If I were to ask you the same questions today that are included in your rebuttal testimony, would you give the same answers?
A. Yes, I would.
MR. GISH: Mr. Vice Chair, Mr. Allen is available for cross-examination.
VICE-CHAIRMAN GARDNER: Thank you.
Mr. Kurtz?
MR. KURTZ: No questions, Your Honor.
VICE-CHAIRMAN GARDNER: Mr. Raff?
MR. RAFF: Just a second.
I believe all the questions that we have have already been asked and answered, Your Honor.
Well, I'm sorry, Your Honor, I do.

CROSS-EXAMINATION

By Mr. Raff:
Q. Mr. Allen, you -- do you work with the AEP Service Corp.?
A. Yes, I do.
Q. Okay. And for how long have you known about no-load costs being allocated 100 percent to the native load customers?
A. I've been a fuel cost witness for a number of

years, and the method of allocation that the companies used has been consistent using an incremental cost method. So I've probably been a fuel witness for eight to ten years, so I've been aware that we use the incremental cost approach where just the incremental cost of the last megawatt hour is assigned to off-system those costs consistent with FERC methodology.

Q. Okay. And do you testify in other jurisdictions on fuel proceedings?

A. I have in the past, yes.

Q. Okay. And to your knowledge, has the issue of no-load costs being allocated 100 percent to native load customers come up before in any other jurisdiction?

A. It hasn't come up as an explicit discussion, but if you look to Exhibit KDP-2 that Dr. Pearce filed, it's very apparent from that figure -- and these are the types of figures that we share with commissions, and most Commission Staff that I'm aware of would be familiar with the methodology that we use for off-system sales assignment where you take that incremental cost, and when you look at that curve, when you see that the curve doesn't end at a zero point, it's very apparent to someone that's an engineer like myself, or other engineers we would deal with in the Staff, that that would have a result of assigning a certain amount of costs to retail customers whether you defined them as no-load costs or minimum-load costs. These type of graphs make it pretty apparent.

Q. You recognize that it was not apparent to Kentucky Power's managing director of regulatory and finance?

A. It may not have been. This is something that's done as part of our settlement process. It's typically been done at the service corporation level. We do these types of calculations.

We're the ones that typically did the testimony on fuel clauses in the past because of the nature of the pool, and the fact that costs were assigned across many of the jurisdictions, and that, you know, for instance, the assignment of some of the output of the Cook unit goes through the pool to Kentucky.

Kentucky Power management wouldn't typically be aware of what the outage schedule was for the Cook Nuclear Plant or the Gavin Plant or the Amos Plant. That information would be something that the service corp would be aware of. And so we always have historically done those calculations because they were system calculations.

Q. Has the issue of allocating 100 percent of no-load costs to native load customers, to your knowledge, been raised in any other regulatory jurisdiction where AEP operates?

A. When I -- and the answer would be yes, I think in other regulatory proceedings parties would have been aware of that. If you look to Exhibit WAA-2, which is an audit that was performed by the FERC staff, in looking at how the Company allocated costs to its wholesale customers, which in this case would be native load customers as compared to off-system sales customers, if you go to what's labeled as page 8 of 8 of my exhibit, which is titled page 4 of the last section of the audit, there's actually a statement.

It's the fourth bullet down in that page that states, "Audit staff reviewed PSO's intersystem sales, also known as opportunity sales, to ensure that wholesale requirement customers were not subsidizing these sales. Audit staff recalculated the FAC to ensure that wholesale requirement customers were not damaged by PSO opportunity sales."

The only way that calculation can be done is to look at a calculation in the manner of the exhibit that I described from Dr. Pearce, which is a graphical representation, KDB-2, of the equation, the quadratic equation that Dr. Pearce described that would exist in our settlement system. So the statement by the FERC staff indicates that they would have had to look at that to make that conclusion.

And the fact that there's, as Dr. Pearce indicated, an A coefficient in that equation says that there are minimum-load or no-load costs that are assigned to retail customers at the end of the day. They're not assigned, but they're a residual that goes to retail customers.

Q. I don't see the words "no-load costs" anywhere in that bullet point, do you?

A. It does not have the word "no-load costs" in there, but the fact of the matter is that's how the calculation has to be done. If you're going to audit how the Company assigns or identifies the fuel costs assignable to off-system sales, you have to do that calculation.

One other piece I want to clarify because we -- I think people misstated things earlier when they said we provided fuel to off-system sales customers at a lower cost than what we provided to our retail customers. What you have to recognize is that we aren't giving the energy to our off-system sales customers at cost. They're paying a market price.

All we're doing is reconstructing that market price to separate it into a profit piece and a fuel piece. Those off-system sales customers are not getting fuel or getting energy at a cost lower than the fuel cost provided to our retail customers.

Q. This was an audit conducted by the Federal Energy Regulatory Commission?

A. Yes, it was.

Q. All right. Has the allocation of no-load costs to native load customers been an issue, to your knowledge, in any state regulatory Commission proceeding?

A. I don't know if any state commissions have explicitly looked at it, but it's something that would be -- I would expect to be part of their review is to understand how we did our calculations of off-system sales.

And because we're one of the companies that shares off-system sales, fairly unique in the industry to have the volume of off-system sales we have and the sharing mechanism we have across our jurisdictions, it would be very reasonable to expect that they've reviewed those methodologies.

And the types of graphs that I showed from Dr. Pearce, those are the types of graphs you would talk about as you're describing why we have the levels of off-system sales we as a company do. Whether they understood it, I don't know, but there's plenty of information in there to allow them to understand that there's a residual that remains for retail customers after the assignment to wholesale customers.

The other important piece to remember when you look at this, those margins from off-system sales that we have at the end of the day, those -- and this is what FERC has described in a lot of their guidance, as long as you cover more than your variable cost, your marginal cost, incremental marginal cost, all of that residual provides a benefit to native load customers, and you should make those sales.

In this case, we agreed, as part of a settlement, that that benefit that normally flows to retail customers for just an interim period stays with the Company. That doesn't mean that when we get to the past period prior to this settlement, December of last year, or July of next year, that these off-system sales calculated in the same manner the Company is doing will provide incremental benefits to our customers.

That's the guidance FERC has provided. As long as you cover a dollar more than that incremental cost, you need to be incented to make that sale so you can provide benefits to your native load customers, and that's what we do with our calculations.

Q. So it's your testimony that you are not aware of the issue of allocating no-load costs 100 percent to native load being an issue in any state regulatory proceeding.

A. I don't recall it being a contested issue. They may have been aware of it. I do not know.

Q. Okay.

MR. RAFF: Thank you, Mr. Allen. I have no further questions.

EXAMINATION

By Vice-Chairman Gardner:

Q. Mr. Allen, in the Mitchell case did you offer any testimony?

A. I did not testify, but I participated in the settlement discussions.

Q. Okay. Did the issue of no-load costs come up?

A. The issue of no-load costs did not come up explicitly in that case, no.

Q. How did it come up implicitly?

A. The one issue that we didn't discuss as a specific element is how NEC costs would change from December 31st to January 1st of 2014, NEC costs being fuel cost.

Fuel costs change for a number of reasons. They change due to timing of new contracts coming on, change in dispatch of the units. So we didn't make an explicit analysis of what the change in the NEC costs would be. NEC costs are what would include the no-load costs.

So to the extent there was discovery in the case asking for the NEC costs prior to the inclusion of Mitchell and after the inclusion of Mitchell, that analysis would have included all of the no-load costs.

And I know you had some questions about the tax -- I think it's 5-10. The impact of no-load cost --

Q. Did you see that?
A. I did.
Q. Okay.
A. The impact of no-load costs would be included as an element of the Mitchell fuel savings. It would be in there as part of the overall savings of the Company you would see.
If you look at these three columns, these are but-for calculations, okay. So they didn't reflect what I would call temporal changes in fuel costs. So the DFGD filing that we talked about, that would have been sometime well into the future. I think that was planned to be in 2015, '16.
We don't include in that column a change in fuel costs due to new fuel contracts. All that's reflected in there is a change in Big Sandy fuel savings, and I can assume from this is it's moving from a high sulfur to a -- or from a low sulfur coal to a less expensive, high sulfur coal. And all we reflected in the second column is just the net change between the cost of the two units.
But the 9 million that Dr. -- or 10 million that Dr. Pearce talked about, those are the type of net costs that would be included in a number like that 16.5. That line item would reflect all the

cost savings.
So if I were looking at that column, what I would determine today is that we've already produced $10 million of the fuel cost savings that are identified in column -- in row 3. So we've got $6.75 million of fuel savings to come up with to get to that 5.33 million -- or 5.33 percent at the bottom line.
Q. As I understood Mr. Wohnhas's testimony, and I could be wrong, it's my recollection that he testified that it was in a conversation with you that he became aware of the issue of no-load costs?
A. I think he indicated it was with Dr. Pearce, but I've had no-load costs with Dr. Pearce in the past, discussions of those as we looked at the curves and how they might change.
Q. Have you had any -- did you have any discussions with Mr. Wohnhas about no-load costs?
A. I have as part of this proceeding, yes.
Q. Prior to this proceeding?
A. No. And just to clarify, as someone that deals with fuel costs in the past as a witness, we don't explicitly look at what are the no-load costs as we're looking at a fuel cost for a customer. What we look at is the net energy cost, what is the

cost to the customer after all things are considered?

The no-load costs plus any benefits due to dispatch or having extra units available so we're never buying in the market, it's that all-in cost, and that all-in cost is the $10 million savings that Dr. Pearce talked about that would be comparable to the 16.75 million on this page.

What we didn't try to do in this analysis is to say what's happening January 1st due to changes in market prices, due to cold weather, market prices going up due to changes in gas forecasts and things like that. This was a but-for analysis. But for the transfer of the Mitchell Unit to Kentucky Power, what would have been the impact.

Q. Okay.

VICE-CHAIRMAN GARDNER: I don't have any other questions. Any redirect?

MR. GISH: Absolutely not, sir.

RECROSS-EXAMINATION

By Mr. Raff:

Q. Mr. Allen, I'm a little slow, and I know it's late, but I'm kind of struggling to understand your response to the Vice-Chairman regarding the no-load costs and the rate change comparison exhibit?

A. Okay.
Q. Were you saying that the no-load costs were reflected in line 3 of the original exhibit, Mitchell fuel savings?
A. What I'm saying is those are the types of costs that would be included in there, and what we can see is that in actuality we've seen $10 million of net savings as a result of Mitchell in the first four months of the year when we were estimating 16.8 million in savings.
Q. But somebody knew when they prepared this exhibit that there were no-load costs. And I think the question is, are those costs reflected in this exhibit?
A. What we've demonstrated through our analysis is that the savings due to some of the other elements we've talked about in the settlement, which were the savings from having the other unit available, having Mitchell available in case Big Sandy was down, when market prices were high and the like, that those savings outweighed any of the costs of the no-load for the first four months of the year to the tune of 9 million -- almost $10 million.
Q. But that --

A. Oh, but this schedule we're missing --

Q. My question, are the costs shown on this exhibit, the no-load costs? I mean, it was revised in this --

A. There is not a cost --

Q. -- in this case to show a breakdown for the Mitchell fuel savings of the same 16,750,000, but then it also shows Mitchell 50 percent no-load costs, $38,000,252 -- I'm sorry, $38,252,000?

A. It does -- it states that, I don't disagree with you. That's what that schedule states, but what I'm telling you is there's no cost called "no-load cost" that hits the books of the Company or that is directly related to a bill we send to a customer.

What's related to the bill we send to the customer is the net energy cost, which is the fuel cost that we use in Kentucky, it's a net energy cost methodology. That includes all of the market purchases, the dispatch of the units, and those types of savings would be in that 16.750. That's where the savings from having Mitchell, we give an estimate of the fuel savings, 16.750 --

VICE-CHAIRMAN GARDNER: Excuse me, were you the one who calculated that number and gave it to

Mr. Wohnhas?

THE WITNESS: I did not.

VICE-CHAIRMAN GARDNER: Who did?

THE WITNESS: He may have calculated it himself. I don't know.

A. But when we talk about fuel savings, we look at total fuel savings, and we've already seen $10 million of fuel savings compared to the 16.750 we were expecting for the entirety of the year.

So what I'm trying to get across is that the numbers we saw in the settlement, the customers are on a rate for the first four months. They've achieved more savings than they should have expected under the settlement.

So this settlement so far, because of the conditions we've experienced, have benefited the customers more than they would have expected under the settlement, and they've benefited the Company by more than we expected under the settlement. It's a win/win.

That's a situation I love to be in at the end of a settlement. That's why I'm a little frustrated that KIUC has a problem with this. They're a winner in the settlement, and what they're asking for is more than they bargained for.

Q. Well, have the -- have the savings been reflected in bills of Kentucky Power customers?
A. What we didn't include on the schedule is how customers' bills would have changed between December of 2013 and January of 2014. What we attempted to do here is say, how do customers' bills for the -- and in this case calendar year 2014, compare to what their bills would have been in calendar year 2014 without Mitchell.
We assumed all other things being equal. We did not try to estimate what I call temporal changes, changes that occur over time. Those would have occurred with or without the Mitchell transfer. So we were trying to isolate the impact of the Mitchell transfer, and I think we did an effective job of it here.
Q. There was an exhibit filed by Dr. Pearce, Number 5, which is titled Kentucky Power Internal Load Full Costs Estimated January-April 2014 Impact Without Mitchell. And I don't know if you can provide it or Dr. Pearce.
It shows for each month of 2014, in the second column, an estimate of costs without Mitchell, and it shows a total for the four months, $90.2 million. Could you or Dr. Pearce provide the

work papers that show how those amounts were calculated for each of those four months.

A. He's indicating yes.

Q. Thank you.

MR. RAFF: Nothing further.

VICE-CHAIRMAN GARDNER: You're free to step down, please.

I'd like to call Mr. Wohnhas again, please.

Is he your last witness?

MR. GISH: He is, Your Honor.

VICE-CHAIRMAN GARDNER: Okay. I just want to understand one point.

* * * *

RANIE K. WOHNHAS, recalled by the Vice-Chairman, having been previously sworn, testified as follows:

EXAMINATION

By Vice-Chairman Gardner:

Q. You're still under oath.

A. Yes.

Q. Let me ask you this. Did you testify earlier that it was Dr. Pearce who communicated to you about the existence of the no-load costs in November of '13?

A. Yes. That's the first -- yes, he was the

person, yes.
Q. Okay. In what context? How did it come up?
A. Came down to describe --
Q. So he physically came to -- to Frankfort?
A. Yes. We had one phone conversation, and then he did come down and make an in-person -- we asked him to come down and talk about it, and, you know, the first one may be by phone, and then later in December by in person, but he did come down.
Again, describing some changes that we brought up or that we -- that were in his testimony, but talk about some of the changes we had in the calculation of no-load costs, the idea of minimum emergency and minimum nonemergency, those changes, and in that context was the first time of discussing no-load cost.
Q. So why did he do that? Why did he come down? Because was it -- was it -- like it wasn't an issue? You didn't understand that this was going to be a --
A. Again, as part of asking if we were going to make a few changes come the first of the year based on this, and he was coming down to explain to us and to get our sign-off that we were all right with those changes.
Q. And what changes specifically were those?

A. Again, it was the change in the -- from the economic minimum to the emergency minimum, and he discusses that in his testimony. That was the main purpose of him coming down and explaining why we wanted to make those changes.

Part of it was because of the pool going away, and so there was some minor changes that were going to be done, and so he brought those to discuss that.

Q. So I don't understand what the changes were. Was it -- change from what to what?

A. How -- how no-load costs -- there was going to be a change in the way no costs -- no-load costs were calculated and totaled between the existing method of -- for the pool in a way from looking at an economic minimum to the idea of where it now goes down to an emergency minimum.

And Mr. Pearce could explain in detail if that needs to be done. That's just in general what was coming down, and it made slight changes to the calculation of no-load cost. Not in the allocation, but in the calculation.

Q. So -- but prior to that, you didn't know that there were no-load costs included, right?

A. I was not aware prior to that the idea of --

in the total fuel, as Mr. Allen testified, you know, the fuel costs that we would look at in our monthly filings, I wasn't aware of the concept of a piece of that was called no-load costs, no.
Q. Was -- was Dr. Pearce, did he participate at all in the -- from the company's perspective with respect to the settlement?
A. Not that I'm aware of, sir.
Q. Did you understand in November the significance of what the change was that they were asking?
A. Well, as we discussed that, we did not see it as a significant change. We -- looking at just, you know, the additional change in the way no-load cost was calculated, but we did not discuss at all or have any even this -- Dr. Pearce did not present to that, you know, we would have this huge increase in no-load costs effective January 1st. It was not anticipated.
Q. Was there a change in how the no-load costs were actually going to be calculated?
A. Yes, there was a slight change to the --
Q. What was that change?
A. Again, I think the best person to explain in detail so you understand it fully would be

Dr. Pearce.

VICE-CHAIRMAN GARDNER: That's all I have. Thank you.

MR. OVERSTREET: May I have one redirect?

COMMISSIONER BREATHITT: May I --

MR. OVERSTREET: Oh, absolutely. I'm sorry, I didn't mean to step on your toes.

EXAMINATION

By Commissioner Breathitt:

Q. Mr. Wohnhas, you had no idea there was going to be this polar vortex, though, when you were having these November meetings.

A. That is correct.

Q. Okay.

A. I mean, that's been our -- there's been -- it was not anticipated that we have this type of load, that we'd have this increase. As I stated a couple times, that if the weather had been the same in '14 as '13, you know, even though we offer our units in as they're available, but if there's not a market for it, they're not taken, and if they're not running, then there's no-load cost.

Q. Do you happen to know -- I know Dr. Pearce has left the stand, but do you happen to know if that 300-megawatt minimum could be a different

number? Could it be 250, could it be 200, could it be 310?
A. Well, I mean, it's different between each unit.
Q. I know. We're talking about Big Sandy 2. Is 300 --
A. It's pretty much at that 300.
Q. Who determines that megawatt number for Big Sandy 2, for example, that 300-megawatt number? How is -- do you know how that's determined?
A. I don't know exactly who -- who within the Company determines that 300.
Q. Could it be a different number? Or is it -- is it a formula that arrives at that no matter what?
A. You would have to ask Dr. Pearce.
Q. Okay.
COMMISSIONER BREATHITT: Thank you. Go ahead.

DIRECT EXAMINATION

By Mr. Overstreet:
Q. Mr. Wohnhas, Vice-Chair Gardner was asking you about the -- your discussions about these certain technical specifics that were modified and updated at the beginning of 2014. I'm going to hand you Dr. Pearce's response to KIUC 2-5 in this

proceeding, and page 2 of 2.

Are these the technical specifications that you had those discussions with Dr. Pearce about.

A. Yes, they were.

CHAIRMAN ARMSTRONG: May I see those?

MR. OVERSTREET: Oh, absolutely. I apologize. I'm sorry, didn't mean to drop it.

CHAIRMAN ARMSTRONG: You just looked at these?

THE WITNESS: I just looked at them, yes, sir.

CHAIRMAN ARMSTRONG: So Dr. Pearce did talk about no-load conditions, didn't he? It says here.

THE WITNESS: Yes. That was what I was just -- he came down and described those issues to us, and when he came down November-December time frame. Yeah, that's what he came down to explain, but in the context of that is -- you know, it's all around no-load, but those were the specific things.

MR. OVERSTREET: May I approach?

VICE-CHAIRMAN GARDNER: Yes.

MR. RAFF: Are you done, Mark?

MR. OVERSTREET: Yes.

CROSS-EXAMINATION

By Mr. Raff:

Q. Just one questions.

Mr. Wohnhas, I'm still trying to kind of understand the reason why the no-load costs were so high in January and February of 2014, and is it because the polar vortex resulted in a much higher than previously experienced demand for Kentucky Power's generation, and that higher demand allowed Kentucky Power to make a significantly greater level of off-system sales, and those off-system sales result in higher costs to rate payers because the rate payers are paying 100 percent of the no-load costs.

A. The -- I'm sorry, that was a long question. I was having trouble following it, and I apologize. Could you repeat that?

Q. It's okay. In trying to understand why the no-load costs were so high in January and February of this year, and you attribute it to the polar vortex. Now, my understanding of the polar vortex was it was very cold weather experienced, which I assume resulted in demand for electricity being much higher than it was, for example, in January of 2013.

A. That is correct.

Q. Okay. So the high demand would have enabled Kentucky Power to make significantly more off-system sales than it had in 2013, and the more off-system sales that you make, is it that that results in higher costs to rate payers because you're incurring more or -- in more hours no-load costs?

A. Oh, it's not just the idea of off-system sales, you know. When you have, you know, number one, the increased load, so in many cases during January you would have all the units dispatched into the system, and I think as we've stated many times, the idea of assigning the highest on the top-down method, but if you have that phenomenon of the load, you will also -- and so those -- as you come down to the minimum, then that gets assigned internal, but you will have additional off-system sales that occur because you have all the units available in the system.

Q. So you're saying if it had not been for the polar vortex, you would not have run one or more of the units?

A. That's -- that's the idea. Even if they were available, as we've said, you offer them in to PJM, all right. PJM is going to accept them based on the load that they see and the prices, and if it had been like 2013, you know, many of those days, even though you had offered into the system, they may not have been accepted as needed for them, and then you would not have run them. If they're not run, then there is no no-load cost.

Q. All right.

MR. RAFF: Thank you.

THE WITNESS: You're welcome, sir.

MR. OVERSTREET: One follow-up.

REDIRECT EXAMINATION

By Mr. Overstreet:

Q. Mr. Wohnhas, Mr. Raff asked you about the effect of the polar vortex, the extremely cold temperatures in January and February on off-system sales.

Isn't it true that as a result of the cold weather experienced in Kentucky Power's service territory, the internal demand of its native load customers also went up.

A. Yes, and that's what was first -- the units were first to take care of the internal load.

Q. And isn't it also true that Dr. Pearce's nearly $10 million calculation shows the savings that the -- over the four months, that the Kentucky Power's native load customers realized as a result of having the Mitchell Unit available to meet that increased internal demand as opposed to having to go out and buy power on the -- in the market?

A. Yes.

MR. OVERSTREET: That's all I have.

VICE-CHAIRMAN GARDNER: Any other questions? Mr. Raff?

MR. RAFF: Nothing further.

VICE-CHAIRMAN GARDNER: Thank you. You may step down.

THE WITNESS: You're welcome, sir.

MR. OVERSTREET: I'm sorry, that's our last witness.

MR. KURTZ: Your Honor, our first witness is Mr. Hayet.

I think the witness is giving the court reporter a copy of his testimony.

MS. HARWARD: Has it been filed?

MR. KURTZ: Yes, it's been filed. Do you need it?

MS. HARWARD: You want me to have it?

MR. KURTZ: No, it's filed with the Commission. I'll take it back. I'm sorry.

VICE-CHAIRMAN GARDNER: That's okay.

* * *

PHILIP HAYET, called by KIUC, having been first duly sworn, testified as follows:

VICE-CHAIRMAN GARDNER: Please state your name.

THE WITNESS: My name is Philip Hayet.

VICE-CHAIRMAN GARDNER: And with whom are you employed?

THE WITNESS: I'm employed with J. Kennedy & Associates, Incorporated.

VICE-CHAIRMAN GARDNER: And what is your position with them?

THE WITNESS: Director of consulting.

VICE-CHAIRMAN GARDNER: Okay.

MR. KURTZ: Thank you, Your Honor.

DIRECT EXAMINATION

By Mr. Kurtz:

Q. Mr. Hayet, do you have in front of you the document, Direct Testimony and Exhibits of Philip Hayet?

A. Yes, I do.

Q. Was this prepared by you or under your direct supervision?

A. Yes, it was.

Q. If I were to ask you the same questions as those contained herein, would your answers be the same?

A. They would.

Q. Do you have any corrections or additions?

A. I do. I think I have three corrections to make, and I'll begin on page 10, and the first correction to make is on line 22, and the word "hours" that appears after "1,622-megawatt" and then the word "hours" should come out. The intention was 1,622 megawatts, which is the peak load in the four month period, just for context.

The second adjustment, or the second correction, I should say, is on page 11, and this was noted earlier today that there was a correction. It's an inconsequential correction, and it's on line number 5 where it reads, "than 31 percent," and that ought to be 30.1 percent, and that had to do with the discussion that you were having with Mr. Ranie.

In fact, the next line down, I might point out, refers to the fact that Kentucky Power, because of those 31 percent of the hours, had to change its reconstruction accounting procedure. So I hope we'll have an opportunity to discuss that further, but that's the second correction.

The third correction is on page 12, and it's the same inconsequential correction. In other words, it says, "during 31 percent of the hours," and that should be -- again, inconsequential correction -- 30.1 percent of the hours. However, the point is still made. And that is all the changes.

MR. KURTZ: Okay. Thank you, Your Honor. The witness is subject or ready for cross.

MR. GISH: Mr. Vice-Chairman, the Company has no questions for Mr. Hayet.

VICE-CHAIRMAN GARDNER: Questions?

CROSS-EXAMINATION

By Mr. Raff:

Q. Can you refer to KIUC/AG's response to Commission Staff's first request, item number 4?

When you were asked why you were not recommending disallowance of the 13.15 million identified in Kentucky Power's response to Staff's second request, Item 4 b. (3) you stated that this would be an unreasonable approach, and you then -- well, could you read the two sentences.

A. Yes, I would. I'd like to state, though, that it says this would not be an unreasonable approach.

Q. I'm sorry.

VICE-CHAIRMAN GARDNER: I'm lost. Can you tell me where this reference is again, please?

MR. RAFF: Staff first request, item number 4, and I don't believe it's in the package that I gave you. It should be in your notebook.

VICE-CHAIRMAN GARDNER: That's not what I've got. And it's Staff's --

MR. OVERSTREET: Mr. Raff, I have an extra copy of it.

CHAIRMAN ARMSTRONG: I don't have it either.

COMMISSIONER BREATHITT: Number 4?

VICE-CHAIRMAN GARDNER: Staff's first set of data requests?

MR. RAFF: To KIUC, the AG.

VICE-CHAIRMAN GARDNER: Oh, okay. ICIC, that's number 9. Okay. Sorry.

CHAIRMAN ARMSTRONG: What is it?

VICE-CHAIRMAN GARDNER: It's KIUC/AG responses to PSC first set of data requests. It was Number 4?

MR. RAFF: Yes, sir. 4 b. (3).

Q. Could you read those two sentences?

A. Okay. Tell me if I'm where you're expecting.

Q. Sure. "This would not be an unreasonable" --

A. Yeah, I've got it. Okay. Perfect.

"This would not be an unreasonable approach for allocating just no-load cost between native load and off-system sales if those were the only costs that had to be allocated. However, because no-load costs, non-no-load fuel costs, and purchase power costs are included in the fuel clause and need to be allocated as well."

Q. Thank you. If it is the case that the non-no-load costs were allocated in your calculation, but not in the response to Item 4 b. (3) of Staff's second request, can you explain why the amount calculated by you, excluding interest, is less than the amount identified in response to Item 4 b. (3)?

A. Item 4 b. (3) is a question to who? I'm sorry. Is that a question that went to the Company?

Q. The Company, I believe.

A. Okay. You might have to --

MR. KURTZ: Can we have a little foundation, Mr. Raff?

That's where you said take the total no-load fuel cost and allocate it by megawatt hours sales that off-system at the native load, is that --

Q. The question to Kentucky Power was the -- refer to the response to item 29e, provide the amount by months that would have been allocated to internal load customers if, quote, "no-load costs," close quote, had followed the allocation of all other fuel costs.

A. Right. I believe I'm familiar with that, and that showed that there was an allocation based on megawatt hours between native load and off-system sale, and I believe that was the 13.15 million that's referred to here in the question, but would you do me a favor and repeat the question to me?

Q. Certainly. The question was if it's true that the non-no-load costs were allocated in your calculation, but not in the Company's response to Item 4 b. (3) of Staff's second request, can you explain why the amount calculated by you, excluding interest, is less than the amount identified by the Company in their response to Item 4 b. (3)?

A. I think it has to do with the fact that we're allocating all of the costs, and there are no-load costs going to both native load and off-system sales under our approach.

It resulted in a small difference, the 12.68 versus 13.15, but I think it is not a -- an attempt to match exactly this number.

I don't have a complete answer for you on that, but I think it is basically our allocation process, sending some of the costs to native load.

MR. RAFF: Thank you. I have no other questions.

COMMISSIONER BREATHITT: I don't have anything.

EXAMINATION

By Vice-Chairman Gardner:

Q. Mr. Hayet, I have one question. I guess I'll take the bait. On page 11 of your testimony, can you describe to me how Kentucky Power changed its FAC reconstruction process?

A. Yes, I can. And that really does relate to the 31 percent of the hours in which -- they're actually selling off-system, the so-called no-load segment, if you will, the minimum segment of the unit, because it's unneeded to serve native load.

There's so much excess capacity. In fact, I even have a chart I'm looking at in front of me that if I were able to show you, I could explain from this chart how there are all these hours in which sales are being made off of the minimum segments.

And when you take it -- when you have a situation in which you're selling off the minimum segments, they had to change the logic. They had to go in and change the reconstruction logic because they may not have done that very often before, or they had an approach to deal with it before, and they eliminated it.

The approach that they had to deal with it before is they said, all right, the minimum is here. That's what we call the economic minimum. Reset the economic minimum to the emergency minimum.

What is the emergency minimum? That's a state that you can operate a unit in. Despite everything we've been hearing about units being unable to operate below the minimum, they can. They can operate at the -- at the emergency minimum. Obviously you would call it the emergency because it's not desirable to operate at the emergency minimum very much, but they do.

And so what they did in the logic previously, perhaps for all the years that they -- prior to how they changed it to now, is like I said, they would drop the emergency -- they would drop the minimum down to the emergency minimum, and then quite likely they weren't in a situation where now they're selling off a minimum segment, and they continued.

And that was one thing that they said, well, they came up with some explanation and said it's really not economic to operate in emergency minimum, so let's stop doing that, but really you have to tie together the pieces, which is this excess capacity, this 31 percent of the time they're selling off the minimum segments. It's happening so much that there was a set of things that were done at that point to change the logic.

And it wasn't just a small change, okay. I know how they characterized it. I think they -- you know, when the wording was clear to say what change did you do to the methodology, they said, we did no change to the methodology. I mean, they were very clear to say that. They said, we changed, certain technical specifications were modified and updated. So it was more than that, and that was one thing that they did.

The second thing that was done was in recognition that you're going to now sell off minimum segments, you have to have a way -- because they spent so much time talking to you about this incremental sale off the top, and in that world you're well far away from a minimum segment, and you are never talking about actually selling off minimum segments, which of course you're doing because you have so much excess capacity.

And will you allow me the opportunity to show you? I have two charts I think will clearly explain what I'm trying to talk about.

VICE-CHAIRMAN GARDNER: Show it to them first.

MR. OVERSTREET: Are these charts in your testimony?

THE WITNESS: They aren't.

MR. OVERSTREET: I'm going to object. I mean, that's -- that's not proper. If he wanted to rely on it, then he needed to include it in his testimony.

VICE-CHAIRMAN GARDNER: I'll agree with that.

COMMISSIONER BREATHITT: I do too.

A. Okay. Well, I'll do my best to explain the situation.

The 31 percent of the hours in which you're selling off the minimum segments, that means that unit really doesn't have to operate to serve native load, and when you sell that capacity off-system, and it doesn't have to serve native load, native load customers effectively get zero megawatts from that unit. But at the same time, they assign the no-load costs to those units -- of those segments to native load customers.

So you could have a situation where a unit --

take Big Sandy 2, for example. Big Sandy 2 could be operating in an hour, it could be operating in ten hours. In fact, it could be operating in 31 percent of the hours where all it's doing is selling off system.

And you take that energy and say, go serve customers out of state or somewhere else in PJM. And at the same time, while you should assign all the fuel costs to the off-system sale, they assign the no-load fuel costs to native load customers.

So the change that was made was they had -- they said, all right, we recognize that with the minimum segment, we're going to allocate the non-no-load costs between native -- we're selling it off, we're going to allocate the non-no-load costs between native load customers and off-system sales.

Or they said if we're selling it off entirely, let's say 300 megawatts in this hour, Big Sandy 2 was entirely not needed to serve native load, then all of the non-no-load minimum segment costs were sent off system.

However, the no-load costs, the no-load portion of the costs of the minimum segment cost, that minimum segment being sold off-system, is always going to native load customers. And the change that they made was to how they went about doing that math associated with taking part of the costs and allocating, part of the costs being the non-no-load costs going off-system, and also making sure that the no-load costs remained with the native load customers.

That was a change that -- those two changes as I just went through were the changes that had to be made as of January 2014 related to the fact that there was excess capacity on the system once Mitchell came on to the system.

VICE-CHAIRMAN GARDNER: Thank you.

Redirect.

REDIRECT EXAMINATION

By Mr. Kurtz:

Q. Just one redirect question, Mr. Hayet. You were describing at length the situation where native load customers get no -- get zero megawatts, but pay for the no-load costs; is that correct?

A. That is correct.

Q. Just very briefly, explain that one more time, where native load gets zero megawatts, but pays for no-load costs.

A. Once again, in the 31 percent of the hours in which these minimum segments -- actually, in a hundred percent of the hours, no-load costs stick with the native load customers, but we were talking about the 31 percent, and we were talking about the change that they made to the logic.

In hours in which, for example, Big Sandy 2, all of that, 300 megawatts of that minimum segment is being sold off-system, it's not needed for native load. Zero megawatts of Big Sandy 2 would go to serve native load customers. All of the no-load costs would get assigned to native load customers.

So you cannot say the native load customers would be indifferent to have those off-system sales being made. They'd be better off if those off-system sales were not made.

MR. KURTZ: No further questions.

VICE-CHAIRMAN GARDNER: Mr. Raff?

Any --

MR. GISH: I have no questions.

VICE-CHAIRMAN GARDNER: Thank you, Mr. Hayet.

MR. KURTZ: Last witness, Your Honor, Mr. Kollen.

VICE-CHAIRMAN GARDNER: Mr. Kollen, good evening.

THE WITNESS: Hi.

* * *

LANE KOLLEN, called by KIUC, having been first duly sworn, testified as follows:

VICE-CHAIRMAN GARDNER: Please have a seat. State your full name.

THE WITNESS: My name is Lane Kollen.

VICE-CHAIRMAN GARDNER: With whom are you employed?

THE WITNESS: I am a vice president and principal with the firm of J. Kennedy & Associates, Incorporated.

VICE-CHAIRMAN GARDNER: You may ask.

MR. KURTZ: Thank you, Your Honor.

DIRECT EXAMINATION

By Mr. Kurtz:

Q. Mr. Kollen, do you have in front of you a document marked Direct Testimony and Exhibits of Lane Kollen?

A. I do.

Q. Was this prepared by you or under your direct supervision?

A. Yes.

Q. If I were to ask you the same questions as those contained herein, would your answers be the same?

A. Yes.

Q. Any corrections or additions?
A. No.
MR. KURTZ: Thank you, Your Honor. Witness is ready for cross.
MR. OVERSTREET: We have no question for Mr. Kollen at this time.
VICE-CHAIRMAN GARDNER: Mr. Raff?
MR. RAFF: No questions, Your Honor.
VICE-CHAIRMAN GARDNER: Linda? I have no questions.
MR. KURTZ: Can I do redirect?
COMMISSIONER BREATHITT: I have a question.

EXAMINATION

By Commissioner Breathitt:
Q. Mr. Kollen, why do you think the point in time was that caused AEP to go to Kentucky and explain a change in how they are doing their -- what was the precipitating event or point in time? Why -- why did it have to be at the end of 2013? Do you know?
A. Well, I think that the problem was is that they knew they were going to run into the minimum segment problem where the sum of all the minimum segments over the six generating units in many hours would exceed the native load.

So the question is, what do you do then with the non-load or the no-load costs, and what do you do with the other minimum segment costs? So what they decided to do, I think, is do something with the other minimum segment costs by allocating those, but they left the no-load costs untouched. Those still get pushed 100 percent to the native load customers, even if the native load customers are getting no generation out of that minimum segment.

So I think they recognized we have a problem because of the excess capacity, and in so many hours we're operating, our native load doesn't even reach the sum of the minimum segments, so we have to do something.

Q. Was this unique to Kentucky, or in your view from preparing for this case, was this a unique Kentucky situation, or was it happening in other places in their service territory?

A. Well, it was unique to Kentucky because of the overlap of the Mitchell capacity with the runout of the Big Sandy 2 capacity in particular, the 17-month overlap and the excess capacity there. That really was the driver.

Q. So that -- do you know -- Mr. Raff was asking other witnesses if they were aware if other states in AEP's service territory were facing this. Would you have -- do you have any knowledge of that?

A. With respect to the no-load costs, no. That has never come up in my experience on any of the AEP companies, and including fuel audits that we have done of other AEP companies.

EXAMINATION

By Vice-Chairman Gardner:

Q. And one follow-up question. And other than no-load costs, what are examples of other costs that are included within minimum segments?

A. I'm not sure exactly what they pack into that, but the no-load costs are the significant subset of the minimum segment costs. And I think there is a recitation of some of those costs in response to one of the Staff data requests.

VICE-CHAIRMAN GARDNER: Okay. That's all.

MR. OVERSTREET: Nothing.

MR. KURTZ: No questions, Your Honor.

MR. RAFF: No questions.

VICE-CHAIRMAN GARDNER: All right. Do you want to introduce your --

MR. KURTZ: Oh, yes, sir. We have exhibits KIUC Exhibits 1 through 11, cross-examination witness.

VICE-CHAIRMAN GARDNER: Any objections?
CHAIRMAN ARMSTRONG: Is Mr. Kollen finished?
MR. OVERSTREET: I'm sorry?
CHAIRMAN ARMSTRONG: Is Mr. Kollen finished, the witness?
MR. KURTZ: Yes, sir. Yes, sir, he is.
MR. OVERSTREET: And I have no objections to these.
VICE-CHAIRMAN GARDNER: So ordered, they're admitted.
(KIUC Exhibits 1-11 admitted.)
VICE CHAIRMAN GARDNER: And did the order set a briefing schedule?
MR. OVERSTREET: It did not, Mr. Vice-Chair. And I've spoken to Mr. Cook, Mr. Kurtz, and Mr. Raff. I know that with the earlier cases, the briefs would be due 28 days from today.
I had suggested to them that given the breadth of this hearing being much broader, that perhaps more time would be appropriate, and they indicated that December 23rd for simultaneous briefs would be okay with them, assuming it's okay with the Commission and everyone.
VICE-CHAIRMAN GARDNER: Any objection? Any objection?

MR. RAFF: No objection to that date, Your Honor.

VICE-CHAIRMAN GARDNER: Okay. So simultaneous briefs are due December the 23rd, and the post-hearing data requests?

MR. OVERSTREET: Right, and with the panel witnesses, I indicated that that was just a single question, it's just really fixing a chart.

VICE-CHAIRMAN GARDNER: Seven days.

MR. OVERSTREET: Seven days. Because these are much more detailed and much more numerous, could we have the 14 days that everyone else got?

VICE-CHAIRMAN GARDNER: Sure, yeah. So with respect to this issue, 14 days for post-hearing data requests. Okay.

Thank you-all so much. Thank you for your-all's patience and going so long. We appreciate it. And appreciate your courtesy to each other.

MR. OVERSTREET: And I'll see you at 10:00 o'clock tomorrow morning.

VICE-CHAIRMAN GARDNER: Yes, sir.

(Hearing concluded at 8:40 p.m.)

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STATE OF KENTUCKY)
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COUNTY OF JEFFERSON)

We, Laura J. Kogut and Jennifer R. Janes, Notaries Public within and for the State at Large, commissions as such expiring 25 July 2015 and 16 May 2015 respectively, do hereby certify that the foregoing hearing was taken at the time and place stated and for the purpose in the caption stated; that witnesses were first duly sworn to tell the truth, the whole truth, and nothing but the truth; that the hearing was reduced to shorthand writing in the presence of the witnesses; that the foregoing is a full, true, and correct transcript of the hearing; that the appearances were as stated in the caption.

WITNESS my hand this 17th day of November 2014.

Laura J. Kogut

Registered Merit Reporter
Certified Realtime Reporter
KY CCR 20042BF060
Notary Public, State at Large

Jennifer R. Janes

Registered Professional Reporter
Certified Realtime Reporter
Notary Public, State at Large