PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider	:	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority	:	Case No. 14-1694-EL-AAM

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DEPOSITION

of Robert W. Bradish, taken before me, Julieanna Hennebert, Registered Professional Reporter, and a Notary Public in and for the State of Ohio, at the offices of American Electric Power, 1 Riverside Plaza, Columbus, Ohio, on Friday, September 25, 2015, at 9:00 a.m.

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SIERRA CLUB EXHIBITS

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ROBERT W. BRADISH,

being by me first duly sworn, as hereinafter certified, deposes and says as follows:

EXAMINATION

BY MR. FISK:

Q. Good morning, Mr. Bradish.

A. Good morning.

Q. I'm Shannon Fisk and I represent Sierra Club in this proceeding.

If you could just state your full name for the record.

A. My name is Robert Bradish.

Q. And by whom are you employed?

A. American Electric Power Service Corporation.

Q. And what is your business address?

A. 700 Morrison Road, Gahanna, Ohio, 43230.

Q. And just to make sure we're on the same page today I wanted to just start out with defining a few terms. If I refer to the applicant in this proceeding, Ohio Power Company, as AEP, will you understand what I mean?

A. Yes.

Q. And if I refer to AEP Generation

Resources, Inc. as AEP Generation, will you understand what I mean?
A. Yes.
Q. And if I refer to American Electric Power Company, Inc. simply as AEP, will you understand what I mean?
A. Yes.
Q. And if I refer to the PPA units, can we agree that means Cardinal Unit 1, Conesville 4, 5, and 6, Stuart 1 through 4, and Zimmer 1?
A. That's correct.
Q. And your current position is Vice President of Grid Development; is that right?
A. That's correct.
Q. And who do you report to?
A. Wade Smith.
Q. And what's his position?
A. Senior Vice President Grid Development.
Q. Do you know who he reports to?
A. Lisa Barton.
Q. And what's her position?
A. She's Executive Vice President Transmission.
Q. And how many people report directly to

you?

A. Directly to me there's four.

Q. And who are they?

A. Paul Johnson, Jeff Lehman, Evan Wilcox, Shawn Robinson.

Q. And did any of them have any involvement in your testimony in this proceeding?

A. Yes, Evan Wilcox.

Q. And what's his position?

A. He's Director of Transmission Planning.

Q. And the other -- so the other three direct reports did not have any involvement?

A. No.

Q. And not direct reports but more generally how many people work for you?

A. I think it's, I don't know the number exactly, but somewhere in the neighborhood of 350.

MR. MILLER: Shannon, can you define what you mean "work for you"?

Q. Well, do you have, like, a department at AEP Service Corp.? How does that work?

A. So I've got different departments, under that there's Paul Johnson and there's a staff underneath him and there's a staff underneath each of the other three guys. So if you add the staff up those from a reporting perspective it's somewhere in the neighborhood I think of 350.

Q. Okay. I won't ask you for all their names.

A. Good.

Q. And in your position do you regularly provide services to AEP Generation?

A. No, I do not.

Q. And do you regularly provide services to AEP Ohio?

A. Yes, I do.

Q. And I believe you state in your testimony you're also President of Pioneer Transmission, LLC; is that right?

A. That's correct.

Q. And what is that?

A. It's a joint venture with Duke to build a transmission line, 765 kV transmission line in Indiana.

Q. And is that, is Pioneer Transmission part of the AEP corporate family? Or is it a separate entity?

A. So Pioneer Transmission would be a

subsidiary underneath AEP Transmission.

Q. And AEP Transmission is a subsidiary of?

A. AEP.

Q. Of AEP, okay. And is AEP Transmission, is it part of AEP Service Corp.?

A. No, it's actually AEP Transmission Hold Co.

Q. Holding Company?

A. Yes. A subsidiary of AEP.

Q. And do you work for AEP Transmission at all?

A. So I work for AEP Service Corp. and AEP Service Corp. provides services to AEP Transmission.

Q. And does AEP as a whole have a regulated and a competitive side to the business?

A. Could you be a little bit more clear I guess breaking down on the competitive side what you mean?

Q. So there's a regulated side, correct, regulated generation in AEP?

A. So there are utilities within AEP, regulated utilities that own generation. If that's what you mean, then yes, those are regulated.

Q. And then do you have a -- and then there's other entities in AEP that are not part of the regulated system?

A. My understanding, AEP Generation Resources is that company.

Q. Do you know, is AEP Transmission within one of those two boxes?

A. AEP Transmission is regulated.

Q. Okay. And in your testimony, and I guess if we can just agree unless I state otherwise we're just going to refer to your May 2015 testimony.

A. That's fine.

Q. On page 2, lines 5 to 15, you have a discussion about there your primary areas of responsibility; is that right?

A. Yes.

Q. And one of those areas is on line 8 asking the adequacy of AEP's transmission network to meet the needs of it's customers. Do you see that?

A. I do.

Q. And what does that work involve?

A. Primarily it involves modeling the transmission network and ensuring that it meets the reliability standards from either PJM or AEP.

Q. Anything else it involves?

A. That's generally what the adequacy means.

Q. And when you say "modeling the transmission network," what sort of modeling are you referring to?

A. These are standard power flow models.

Q. Which modeling do you use?

A. Well, for -- so help me a little bit more. When you say "which models" meaning?

Q. Like Siemens.

A. Oh, okay. We have PSSE, which I believe is a Siemens. It was PTI initially and they were bought and sold by several companies, I think Siemens might be the owner, I'm not sure. And then we also use a program called Terra and we use a program called MUSD, M-U-S-D.

Q. What does "MUSD" stand for?

A. I don't remember.

Q. And do you know PSSE, what sort of modeling analyses can you do with that program?

A. Load flow and stability.

Q. And Terra?

A. I know we can use it for load flow. I don't think we use it for stability. Just primary load flow type analysis.

Q. And MUSD?

A. That's more load flow analysis also but it's primarily focused transfer capability analysis. And when I say "load flow" and "power flow," I'm using them interchangeably.

Q. Okay, fair enough.

And so is there a major difference between Terra and PSSE in terms of if you're looking at load flow?

A. No, I don't think there's any major difference. I think it's more of one of user friendliness in terms of the analysis you want to do which one has got a better user interface.

Q. And the modeling of the transmission network for assessing the adequacy of the network, is that all done in-house?

A. Yes, it is. Well, for this analysis it was all done in-house.

Q. Okay.

A. We do use contractors from time to time for certain specific analyses, but that was not the case here.

Q. When would you do -- when would you use a contractor?

A. If we're doing simple analysis where maybe a load wants to connect, small load wants to connect, then we would let them do that and be supervised by one of our internal engineers.
Q. Any other cases where you'd use a contractor?
A. I think that's primarily it. I can go back and check with my team to see what other places we might use them but that's been the majority of it.
Q. And is there any reason you didn't use a contractor in this case?
A. We thought the analysis was something that was best done by the internal team.
Q. Was there ever a discussion should we get a contractor to do it instead of internally?
A. No. No.
Q. And you referred to I believe the modeling of the transmission network, you do it to ensure that you're satisfying NERC, PJM, and AEP's standards; is that right?
A. Plan criteria.
Q. Planning criteria. Are there any major differences between those?
A. I don't think there's any major

differences. There may be a couple small things but they're relativity consistent because they're all based primarily on the NERC transmission planning standards.

Q. And when you were doing load flow or power flow modeling, do you personally do that or is it somebody in your shop?

A. My staff does that.

Q. And who typically does that?

A. There's a variety of people. So underneath Evan Wilcox he has a team of people who do this type of analysis.

Q. And is Evan and his team, is that who did the analysis in this proceeding?

A. That's correct.

Q. Have you ever personally done load flow modeling?

A. Yes, I have.

Q. How frequently?

A. Back when I first started as a planning engineer when I joined AEP I did that all the time --

Q. And when was that?

A. -- as part of my job.

Q. How long ago was that?

A. Well, I joined in '87.

Q. So when's the last time you have personally done load flow modeling?

A. I believe somewhere in the neighborhood of 1997 timeframe.

Q. So since then your role has simply been to review results of modeling, not actually do it?

A. That's correct.

Q. And do you frequently review results of modeling?

A. Yes.

Q. And when you're reviewing the results, typically is there some sort of report that you're reviewing or how do you go about reviewing it?

A. It varies. Sometimes there's reports written, sometimes it's -- it could be a PowerPoint presentation, sometimes it could just be a discussion with my directors, managers.

Q. And when would you -- when would there be a report written regarding some transmission modeling that's been done?

A. Typically we only write reports if they're required.

Q. Required by whom?

A. The only place right now I think we have a requirement for that is within ERCOT. PJM and SBP don't require formal reports but ERCOT does into our RPG process. Just their regional planning process require reports.

Q. So for PJM if you do transmission modeling and then how do you communicate results to them?

A. My team will send them the results. So they'll send them our solutions either through files that PJM can grab and use and test in their own system typically.

Q. Okay. So you run the model and then there's a file that comes out with results that someone can then, PJM can then review and rerun to ensure it's accurate?

A. Yeah. We actually don't send PJM results, we actually send them a file that says this represents our solution.

Q. Okay.

A. So they can read the file in, it will make the changes to their model and they'll test that solution and they'll see if it works or not.

Q. Okay.

A. So really they're just exchanging, at that point we're sending our solution, they're testing that solution to see if it works.

Q. So in this proceeding, and we'll get more in the modeling later, but is there such a file with solutions that you could send to PJM so they could test?

A. I don't know. We didn't plan to send anything to PJM in this analysis, so I don't know if a file exists or not.

Q. So you're not even sure -- leaving out sending it to PJM, do you know whether there's a file with the solutions identified?

A. Yes. So there certainly is. So we developed exclusions for the problems and so there would be a model with that solution in it that was tested by the team to make sure it solved the problems. But there wouldn't be any separate file that we would have prepared to send to PJM because we didn't do that in this process.

Q. Okay. And have you, in this case have you seen that file or that model with the solutions in it?

A. No. I don't review the details in the model.

Q. And then you also, going back to your testimony on page 2, line 12, one of your other primary areas of responsibility is advanced technical/analytical studies in support of planning, engineering, design and operation. Do you see that?
A. I do.
Q. What does that work involve?
A. So those are the more detailed technical analysis, like systems stability analysis. Sometimes called dynamics stability analysis. We also look at EMF, electromagnetic frequency type issues associated with transmission lines.
And we'll do switching studies. So we look at when you switch a transmission line, you look for transient voltages and things like that, those are much more detail types of studies.
Q. And systems stability analysis, stability analysis. How does that differ from a power flow analysis?
A. It's a much more detailed representation of generation. So rather than looking at general power flow, it's a time base simulation of the actual performance of the generating unit. Typically what you do, you apply a fault and look how that generator

performs, whether it stays synchronized to the grid or whether it trips over line.

Q. So that's more of a reflection of what might happen in reality than, say, just a load flow analysis?

A. Oh, no. No, it's just a different type of analysis.

Q. And are there different modeling programs you use to do a system stability analysis?

A. I believe we use PSSE for all our stability studies.

Q. And do you do those all in-house?

A. Subject to checking with my team, I believe so.

Q. Any other modeling programs you do for systems stability analysis?

A. I don't think so. I think we primarily use PSSE.

Q. And then I believe you referred to a switching analysis.

A. Yeah, transient type switching analysis.

Q. And what is that?

A. Basically what happens when you open up transmission lines, there are transient voltages that get induced on the system so you have to make sure that the insulation is going to be capable of withstanding those voltages.

Q. Going down to line 16 through 19 on page 2, you identify some states where you have previously submitted testimony; is that correct?

A. That's correct.

Q. And is that an -- the states that you list there, are those all in, like, the Public Utilities Commissions?

A. That's correct.

Q. Is that a complete list of states where you have submitted testimony in Public Utility Commissions?

A. I would put Ohio in there now, but, yes.

Q. And with regards to Arkansas, was there only a single case where you submitted testimony or would have been multiple?

A. I'm not going to be able to remember the details, how many cases that were submitted actually. I can't recall if it was one or multiple.

Q. Do you recall the last time you --

A. It was at least one.

Q. Do you recall the last time you submitted testimony there?

A. It's been a couple years. I think was on the -- associated with our Trans Co. that we were representing for Arkansas.

Q. And you think it was 2012 timeframe?

A. It's been within the last five years. But time flies.

Q. And were you ever deposed in a proceeding in the Arkansas PSE?

A. No.

Q. Were you ever cross-examined at a hearing in the Arkansas PSE?

A. No.

Q. And how about Indiana, when was the most recent testimony you've done there?

A. Probably the most recent was, and I don't know if this qualifies as testimony, but we were asked to go and discuss a load shedding event that we had. So that was 2013 timeframe.

Q. But that wasn't written testimony.

A. No, that wasn't. I can't remember what the case was now but it's been a while. Been longer for Indiana.

Q. So more than five years ago.

A. Yeah, I think so.
Q. Do you know, were you deposed in that proceeding?
A. No, I was not.
Q. How about cross-examined in a hearing?
A. No, not in Indiana.
Q. And Michigan, when was the last time you submitted testimony?
A. That was even longer ago. I couldn't tell you what year.
Q. But more than --
A. Yeah, it's been a while.
Q. More than five years?
A. Yes.
Q. And do you know, were you deposed in that proceeding?
A. No.
Q. How about cross-examined?
A. No.
Q. Oklahoma, when was the last time you testified there? Or submitted testimony there.
A. I believe it was 2013.
Q. Which proceeding was that?
A. That was the base rate case for Public

Service of Oklahoma.
Q. And what was your testimony there regarding?
A. Supporting the need for transmission that we had built.
Q. Was that in any way related to any retirements of generating units?
A. No, it was not.
Q. And were you deposed in that proceeding?
A. I was not.
Q. How about cross-examined at the hearing?
A. Was not.
Q. Do you recall any other Oklahoma testimony?
A. No. Not testimony, no.
Q. And Virginia, last time you submitted testimony there.
A. So in Virginia it's got to be close to ten years ago. I don't remember exact date.
Q. And have you ever in general been deposed?
A. No.
Q. Have you ever testified in a hearing?
A. Yes.
Q. Where?

A. Virginia.
Q. There we go. And have you ever submitted testimony in a court proceeding?
A. Be more specific.
Q. State or Federal Court.
A. No.
Q. And have you ever been a witness in a State or Federal Court proceeding?
A. No.
Q. And outside of this current proceeding have you ever been involved in transmission reliability issues related to proposed retirements of generating units?
MR. MILLER: Can you be more specific?
A. I'm not sure what you mean.
Q. So in this proceeding you're sponsoring testimony regarding reliability impacts if certain coal plants were to retire.
A. Right.
Q. Have you ever, outside of this proceeding, analyzed the transmission and impacts of retiring of some generating units?
A. In some proceedings somewhere?
Q. No, just in general. Like, do you have

any experience doing that?

A. Yes. We would do that on a regular basis anytime generators retire, especially true with the MATS retirements. We did a lot of analysis around the MATS retirements.

Q. And you were involved in those analyses?

A. Yeah, the same capacity I am today.

Q. And what sort of analyses did you do with regards to those retirements?

A. So we did very similar analysis to what we did here, we looked at the retirements of those generating units and assessed their impact on the grid and what we, you know, we not only looked at our generation retirements but we had to look at our neighbors because they were also impacting -- having impacts on our grid.

So we've looked at that, we started that process in 2012 when folks started announcing their retirements for the MATS and we've been doing that ever since because we keep finding issues.

Q. Sure. And were any of those analyses regarding MATS retirements system stability analyses?

A. Yes, at some point we had to do system stability analyses, I can't recall exactly which step along the way, but they would have been part of, ultimately part of PJM's RTEP process stability analysis would have been done.

Q. So you have done a system stability analysis to then submit something to PJM's RTEP process?

A. Well, we would have, PJM would have run a stability analysis and would have shared those results with us. We would have done our own stability analysis to see if there's a need for system reinforcement as a result of those analyses. So we would have gone back and forth with PJM in that process.

Q. And why would that process involve system stability analysis rather than, say, just a load flow study?

A. Well, in that case we were actually looking at a very specific situation where units had announced their retirements and were moving forward. And so part of the analysis involved system stability, part of our planning requirements require us to run a stability study, if a plant's actually going to retire, and we would do that detailed analysis.

Q. So, for example, in this proceeding if any of the PPA units were actually going to retire, you would do, at some point you would do a system stability analysis to evaluate the impact.
A. That's correct.
Q. But that has not occurred here.
A. Has not.
Q. Outside of the MATS retirement scenario has there been any other times that you have been involved in evaluating the transmission impacts of retirements?
A. Well, sure, we did it with the Clean Power Plan.
Q. So you've done -- what did you do with the Clean Power Plan?
A. We assessed the impact of the retirements that EPA thought would happen under a Clean Power Plan, we assessed that impact on the transmission system.
Q. And what sort of modeling did you do to assess those impacts?
A. Power flow modeling.
Q. And no system stability analysis?
A. That's correct.

Q. And when did you do that power flow model?

A. The end of, somewhere in the end of 2014. The last quarter maybe, second half.

Q. So that was when the Clean Power Plan was proposed for?

A. That's correct.

Q. Have you done any such analysis since the Clean Power Plan has been finalized?

A. Have not.

Q. Do you know if anybody in the AEP family has?

A. No.

Q. Would there be any other section or department in AEP that would be doing transmission reliability analyses or is that all done through the section you're in?

A. Yeah, it would all be done by my section.

Q. So outside of the MATS and the Clean Power Plan assessments, any other assessments you've been involved in of transmission impacts of retirements?

A. Just in general anytime there's a change in generation on the system and whether it's related to MATS or not or generally retiring, and that analysis would be done. And so if it falls in generation, that would have an impact on our system, we would do that. So anytime a generator retires, that process would happen.

So my team is regularly involved in those types of evaluations. I don't have any specific units off the top of my head that I could say, but generating units are retiring on a fairly regular basis.

Q. And so that's not just units in the AEP zone but just that could affect the AEP zone even if they're outside?

A. That's correct.

Q. And just to make sure we're on the same page, when I said "AEP zone," I guess I was referring to the portion of AEP in PJM; is that right?

A. Yeah, that's how I interpreted it.

Q. Okay, great. And that covers a multi-state area, correct?

A. It does.

Q. Is it a portion of seven states I believe?

A. I think that's correct. I can name them: Michigan, Indiana, Ohio, West Virginia, Virginia, Kentucky, Tennessee. Seven.

Q. And then there's also an AEP, separate from PJM there's AEP in kind of south central part of the country; is that right? Like Texas, Oklahoma.

A. Yeah. So we do have operations in, would be in the states of Oklahoma, Arkansas, Louisiana, Texas.

Q. And are you responsible for transmission there too?

A. Yes.

Q. And are you just at a general level familiar with the proposed agreement under which AEP-Ohio would pay to AEP Generation the cost of operating the PPA units?

A. I am familiar.

Q. And can we agree to refer to that proposed agreement as the affiliate PPA?

A. Yes.

Q. When did you first hear about the affiliate PPA?

A. First I can recall is right around the time we got asked to do a study to look at the transmission impacts.

Q. And when was that?

A. Sometime in '14 right around when we did the study. So it would be, I don't know the exact but somewhere July probably, June-July timeframe. I'm not sure, have to think about that a little bit more but that's the first I heard.

Q. June-July 2014.

A. Somewhere in that time.

Q. And who asked you to do the study?

A. I'm not sure who actually made the request. It was -- I don't know, I can't remember if it was through our -- probably through our legal counsel. Would have been Steve Nourse. I'm not sure who else. I don't know.

Q. Do you recall who outside of your Transmission group you've spoken to about the affiliate PPA?

A. Yes. It would have been the Regulatory group under Rich Muczinski. So we've talked to them.

Q. Muczinski?

A. Yeah.

Q. And do you know, is his group part of AEP Service Corp.?

A. They are.

Q. Anyone else you've spoken with outside of your transmission group about the affiliate PPA?

A. Well, yeah, I've spoken to other people

about it. Lots of people.
Q. Sure. Anybody outside of AEP? Not your friends or something but anybody outside of AEP, anybody inside of AEP.
A. I mean, in general we've got a case filed, so it comes up and we talk about, we read about it in the paper and stuff like that. So we in general will talk about those things.
Q. In terms of your analysis that you're sponsoring in your testimony here, is there anyone else you've spoken with at AEP about that?
A. No. It's just within the Transmission organization, and then the Regulatory group.
Q. And what were your discussions with the Regulatory group?
A. Most of that's along the issues of responding to RFIs and things like that to help facilitate that process. And they also helped facilitate the development of the testimony.
Q. And how so?
A. They just coordinate and make sure we're meeting our deadlines and getting stuff together. Making sure we're reviewing our testimony and if we had any edits and stuff like that.

Q. Do they have any substantive role in your testimony?

A. No.

Q. Did you draft your testimony yourself?

A. With my team.

Q. Who on your team helped you?

A. Evan Wilcox. And I'm not sure who he relied on, if anybody.

Q. So did he draft it and present you with something to review? How did that work?

A. Yeah, typically that's how it worked is we discuss what we want to do, it gets drafted up and then hand it to me to read.

Q. And how long did you spend reviewing the draft?

A. I don't know how many versions I looked at. Just I read it, provide comments on it, and send it back. It doesn't take too long to read it and respond.

Q. So do you recall having significant substantive comments on what Mr. Wilcox had drafted?

A. Well, we talked about it first, so we talk about, hey, these are the types of things we need to put in there, and then he drafts what I've asked and then we go through it. So I don't remember all the different variations of what I commented on stuff like that. Ultimately this is where we landed, I guess.

Q. Do you recall having any disagreements with Mr. Wilcox about what should be in the testimony?

A. No.

Q. And did anyone else besides Mr. Wilcox and his team have any substantive input into your testimony?

A. No.

Q. And are you aware there's a draft contract setting forth the terms and conditions of the proposed affiliate PPA?

A. Just generally aware.

Q. Did you have any role in negotiating that contract?

A. Oh, no.

Q. And so you're not in this proceeding offering any opinions regarding the terms or conditions of the proposed affiliate PPA?

A. I'm not.

Q. Are you aware just generally that

AEP-Ohio's application also seeks approval for inclusion of the net impacts and affiliate PPA in a rider?

A. I don't know that much about it in terms of the details of how they actually want to do it.

MR. MILLER: That's pretty vague, what do you mean by "aware"?

MR. FISK: I guess just wanted to know does he know that there's a proposal for that, not any details of it.

A. I haven't looked at the details or anything like that, I just know we proposed this PPA.

Q. So you did not have any input into constructing the proposed PPA.

A. None.

Q. And you're not offering any opinions regarding the PPA in this proceeding.

A. I am not.

Q. And your testimony in this proceeding addresses potential reliability impacts if the affiliate PPAs were to retire, right?

A. That's right.

Q. So if the affiliate PPA units did not retire, the reliability impacts you identify would not occur; is that right?

A. I think that's generally true. All things else not changing, yeah, I think that's generally true.

MR. FISK: Somebody just join?

MS. PETRUCCI: Yes, it's Gretchen Petrucci.

MR. FISK: Hi, Gretchen.

Q. Do you know whether if the Commission does not approve the affiliate PPA and its inclusion in the PPA rider whether AEP Generation would retire any of the PPA units?

A. I have no idea.

Q. Have you ever seen any analysis of whether those units would retire if the affiliate PPA and PPA rider were rejected?

A. I'm not involved in any of those types of analyses and have not seen any.

Q. And has anyone told you that any of the PPA units would retire if the Commission does not approve the affiliate PPA and PPA rider?

A. No, they have not.

Q. And if the PPA units were sold to a third party as opposed to retired, do you believe the reliability impacts you identify in your testimony would occur?

A. Only if they close them.

Q. Fair enough.

And we've mentioned previously PJM, of course. What is PJM?

A. It's the RTO that operates the markets here and in the Mid-Atlantic states.

Q. And RTO is Regional Transmission Organization?

A. That's correct.

Q. And are you aware that the owner of a generation unit must notify PJM if the owner intends to retire that unit?

A. Yes.

Q. And to your knowledge has AEP Generation notified PJM of its intent to retire any of the PPA units?

A. Not that I'm aware of.

Q. And would you agree PJM is responsible for ensuring reliability within its footprint?

A. Yes.

Q. And do you think PJM is capable of ensuring such reliability?

A. Yes.
Q. Okay.
A. They get a lot of help from us.
Q. And on page 5 of your testimony, on lines 5 to 16 you have a discussion there about Reliability Must Run contracts; is that correct?
A. Yes.
Q. And can we agree to refer to that as RMR contracts?
A. Yes.
Q. And what is your understanding what an RMR contract is?
A. My understanding is just it's a kind of a short-term measure to keep generating units that have announced that they may retire, to keep them running until such time the reliability impacts can be assessed and addressed by the RTO.
Q. So if a generation owner proposes to retire a plant by X date and PJM determines their reliability impacts, they can't be fully addressed by that date, PJM would then propose an RMR contract to keep the plant running?
A. That's how I understand it works, yes.
Q. And the RMR, under the RMR contract the

generation owner would be paid to keep the plant running, correct?

A. That's correct.

Q. And such payments would last until the transmission upgrades needed to address reliability impacts are completed?

A. Yes, that's my understanding.

Q. Have you ever had any involvement in negotiating RMR contracts with PJM?

A. I have not.

Q. Do you know who at AEP would be in charge of that?

A. It would be someone in the Generation organization. So I would not be involved in those types of negotiations.

Q. So someone at AEP Generation?

A. Well, I guess it would depend. Right? If it's an AEP Generation unit, then they would be involved. If it's one of the regulated units, then they would not.

Q. And your group wouldn't have any role in those negotiations?

A. Not in the contract negotiations, no.

Q. And on lines 14 to 16 of your testimony on page 5 you note that there is no obligation for a generator owner to accept an RMR designation; is that right?

A. That's correct.

Q. Do you know of any generation owners who have sought to retire a plant and were offered an RMR contract by PJM that refused to enter in such a contract?

A. I don't have any knowledge of RMR contracts within PJM, so no. I don't know if there has been that situation or not. I don't personally recall each and every one so I couldn't tell you if there has been or has not.

Q. Okay. So you can't identify any individual utility that said no, we are just going to shut down, we don't want your RMR contract?

A. I'm not aware of any. That doesn't mean there hasn't been.

Q. And going down lines 20 to 21 on page 5 there, you have a sentence there However, one can never be certain if transmission improvements can be implemented. Do you see that?

A. Yes.

Q. And do you know of any situations in which transmission improvements needed to address reliability impacts from a proposed plant retirement couldn't be implemented?

A. Yeah. It's not implemented so much as it's maybe implemented in a timely manner. There are transmission projects have been proposed that have been rejected. We just recently had one in Arkansas where ultimately the state said we have justification to move forward with it but as it related to generation retirements, we've got that situation now with the MATS retirements where we've got MATS, a project that was driven by the generation retirement with MATS that is not complete yet but the generation has been retired, so what we've done is we've put in place an operating procedure, basically load-shedding procedure.

So if we get ourselves into a certain situation, we will just shut the load in the area to prevent the larger, you know, collapse of the system. That operating procedure will stay in effect until the project's done.

Q. Okay. And --

A. So those situations can exist.

Q. Is that just one situation, the load shed, one that you know of?

A. Yeah, that's the one we currently have on our system as involves the MATS.

Q. Do you know of any other such situations?

A. I don't know. Other than there's been a lot of generation retirements and I don't know if they've got similar situations or not.

Q. And are you able to say on the public record which retirement that involves?

A. Well, it's the collective. You can't really identify any one unit, so it's the fact that we retired a bunch of generating units, "we" being AEP, FirstEnergy retired generating units, other companies have retired generating units and it's the collective impact of all that that results in this outcome. So you can't really assign those to anyone.

Q. And so as a part of that there's a specific transmission project that's been identified as needed but that hasn't been completed yet?

A. That's correct.

Q. Are you able to say which project that is?

A. It's we call it the Canal Valley Area Improvements. It's basically rebuilding a 138 kV corridor from southern -- from the Ohio-West Virginia border area down through the Charleston, West Virginia.

Q. And that project has been approved by PJM?

A. Yes.

Q. And it's in process?

A. Yeah, it's under construction.

Q. And --

A. Not under construction, it's certainly under the siting. I don't know if we've started physical construction yet but it's moving forward and it will get done eventually.

Q. Do you have any sense of how delayed it is?

A. I think it's probably going to be about a year and a half.

Q. Do you know why it was delayed?

A. Not so much delayed as the timeframe we had to get it done wasn't adequate. So we started the analysis in 2012 and these plants were going to retire in 2015 and because of we have to rebuild this major corridor. It just takes longer. So the time was a three-year window and it just takes longer to build it than three years.

Q. So this is a situation where it's not that the transmission improvement can't be implemented, it's just that it can't be done in the timing that was set forth by MATS.

A. Yeah.

Q. So do you know of any situations where the transmission improvement simply cannot be implemented when there's a retirement that's been proposed?

A. Good clarification. For retirements not on our system. I can't speak to the other generation retirements but I don't recall any on our system.

Q. And on the Canal Valley Area Improvements do you expect to have to do load shedding at some point?

A. We hope not.

Q. And then you referred to an Arkansas project getting rejected?

A. Yeah, there was recently a project we had in northern Arkansas that ended up getting rejected.

Q. But that was not related to any sort of retirements.

A. No, it was not.

Q. So if timing is not an issue with regards to a retirement of a unit, are you confident that necessary transmission projects to allow for such retirement could be completed?

A. In general, yes. I mean, you always run into the issues of siting and trying to get something sited so it's hard to speak about future siting challenges you might have. In general we would ultimately find a solution, if we had enough time we could get that built.

Q. And it's your understanding that under an RMR contract PJM would continue to pay for the continuing operation of the plant during that timing, right?

A. That's my understanding, yes.

Q. I'm moving on to another topic, so if you need a break, let me know.

A. I'm good right now.

Q. Okay, figured I'd ask.

A. Appreciate that.

Q. Sure. Let me go ahead and mark this.

(EXHIBIT WAS MARKED FOR IDENTIFICATION.)

Q. Mr. Bradish, you have been handed what's been marked Sierra Club Exhibit 1, which is a Supplemental Attachment 1 to Sierra Club RPD-2-71; is that correct?

A. Yes.

Q. And this is an 11-page document entitled PPA Deactivations - Ohio Transmission Assessment; is that right?

A. Yes.

Q. And have you seen this document before?

A. I have.

Q. And did you create this document?

A. I did.

Q. Excellent. And did anybody work with you on creating this document?

A. Yes.

Q. And who?

A. Evan. Evan and his team.

Q. Okay. And what generally is this document?

A. This document generally describes the process we went through to assess the transmission system and identify the solutions that we needed to solve the reliability problems.

Q. And so this Sierra Club Exhibit 1, does this reflect the transmission impact study that is discussed starting at line 14 on page 6 of your testimony?

MR. MILLER: Shannon, when you say

"reflect."

Q. Or summarize. I just want to make sure they're the same, there's not another transmission impact study.

A. Oh, no. Yes.

Q. And then on page 9 of your testimony, line 4, you refer to an estimated cost for minimum upgrades required is 1.6 billion. You see that?

A. Yes.

Q. Is that 1.6 billion figure for the transmission upgrades that are addressed in Sierra Club Exhibit 1?

A. Yes.

Q. And if you could turn to page 2 of Exhibit 1. The page is entitled Background; is that right?

A. Yes.

Q. And in the middle of the page under "Used generic commercial probability." Do you see that?

A. Uh-huh.

Q. There's a reference to "FSA."

A. Yes.

Q. What is that?

A. Facility study agreement.

Q. What are those?

A. They're agreements that PJM enters into with the generating units that generating units commit to doing a facility study where they figure out what the detailed transmission requirements are for the unit to connect to the grid.

Q. And ISA?

A. Interconnection study agreement.

Q. And what is that?

A. That's the final agreement where the generators, all the studies have been completed and the generator signs an agreement with PJM they accept whatever cause and responsibility there is and they're ready to connect to the grid.

Q. So you're familiar, I assume, with the PJM queue?

A. I am.

Q. And is that interconnection study agreement in the last step before the plant goes into service?

A. That's correct.

Q. And if you turn over to page 3 of the Exhibit 1, says Scenario Studied for Transmission Solutions Development; is that right?

A. Yes.

Q. And it says "Retirement to Cardinal, Stuart, and Zimmer plants plus the projected retirements of plants affected by 111(d)," right?

A. It does.

Q. Should Conesville be in there too?

A. It should. I don't know what happened there. Just to be clear, that is Cardinal Unit 1.

Q. Okay, just Unit 1.

A. Only.

Q. All right. And one other what I think is a typo. If you turn to page 10, at the very top, well, under Scope and Cost Mitigation, it says "Stewart and Zimmer." Is that supposed to be S-t-u-a-r-t?

A. Yes.

Q. So that's the same plant as Stuart, right?

A. Yes.

Q. I just wanted to make sure the record is clear there.

A. Yes.

Q. And so just to be clear, you have not done any transmission reliability analysis of retiring either Tiger Creek or Clifty Creek, correct?

A. That's correct.
Q. So in your analyses here it's assumed that those plants would continue operating?
A. That's correct.
(EXHIBIT WAS MARKED FOR IDENTIFICATION.)
Q. You've been handed an exhibit marked Sierra Club Exhibit 2 which is the company's responses to Sierra Club interrogatory 2-070; is that right?
A. Yes.
Q. And it's double-sided so there's stuff on the next couple pages there.
A. Yep.
Q. And you are the witness on this response?
A. Yes.
Q. And you've seen this document before?
A. Yes.
Q. And did you draft these responses?
A. I reviewed them with my team. I didn't actually write them myself.
Q. Did Mr. Wilcox write them?
A. Wilcox or his team.
Q. And if you look under the initial response subsection a.ii.

A. Yes.
Q. And the third sentence says "AEP developed and assessed five different scenarios." Do you see that?
A. Yes.
Q. And there's then those five are listed. Are these the same scenarios that are discussed in the Transmission Assessment, Sierra Club Exhibit 1?
A. Yes.
Q. And so just to make sure the record is clear, scenario 2 says retirement of Cardinal units, plural. Should that be just one unit?
A. Yes, should be Unit 1.
Q. And then under scenario 4 when you refer to Cardinal, it's just Unit 1?
A. Unit 1.
Q. And I assume under scenario 5 only Cardinal Unit 1 was retired?
A. Yes.
Q. So which of the five scenarios listed here, assuming it's one of them, led to the $1.6 billion cost estimate?
A. Scenario 5.
MS. PETRUCCI: This is Gretchen. Can I

have that answer reread?

(Record read.)

Q. So going back to the Transmission Assessment, page 8, it says AEP Upgrades Scope and Cost. Do you see that?

A. Yes.

Q. And there's a list of ten projects.

A. Uh-huh.

Q. And $1.64 billion.

A. Uh-huh.

Q. So then ten projects came out of scenario 5?

A. That's correct.

Q. And then if you flip over to the next page, Scope and Cost of Mitigation Plans, and then it says Conesville Units 4, 5, and 6. Are those numbers from scenario 5 or are they from scenario 1?

A. Scenario 5.

Q. And that's the same with the other scenarios or the other sets of costs identified on page 9 and 10?

A. That's correct.

Q. And in the study on what date did you assume Cardinal Unit 1 would retire?

A. It was all at 2019. So it would have been retired before the summer of 2019.

Q. So like June 1?

A. Yeah.

Q. And on page 10 of the Transmission Assessment, so the top one, Stuart and Zimmer plants, so you have not reported, am I correct, the transmission upgrades that would be needed if only the Stuart units retired? Is that right?

A. That's correct.

Q. And why?

A. Just when we did this analysis, because they're electrically very close, we just bundled them together.

Q. Would you agree that Zimmer could continue operating even if Stuart retired?

A. Yes.

Q. Do you have any sense of what the transmission impacts would be if only Stuart retired and Zimmer kept operating?

A. I don't.

Q. Do you know what upgrades might be needed if only Stewart retired and Zimmer kept operating?

A. I don't.

Q. Would it be safe to say that it would be, the upgrades would be needed would be less than the upgrades needed with both Stuart and Zimmer retiring?

A. Yeah, I think it's safe to generally say that, yeah. If fewer plants retired, fewer upgrades would be needed. I don't know exactly which one is the -- what the outcome would be until I did the analysis, but yes, generally.

Q. So you would need to do a new load flow analysis.

A. Yes.

Q. So scenario 5 assumes the retirements of all these PPA units plus a set of units impacted by the Clean Power Plan.

A. That's correct.

Q. And when in the modeling did you assume the Clean Power Plan units would retire?

A. 2019.

Q. And why did you assume that?

A. That was the case we used, so the case was representative of the 2019 time period to 2019 RTEP case. So what we did was we modeled what affects would happen in 2019 if all these plants retired.

Q. And the Clean Power Plan is not going to into affect until 2022, correct?

A. That's my understanding. The new rule coming out is 2022 is the initial date; however, if you want to be compliant in 2022, you need to make actions before you get to that point, you got to make decisions before you get to that point.

So decisions are going to have to be made about what's going to happen, so the states I believe are going to put together their state implementation plans and stuff like that over the next few years. So they're going to be making those decisions and those decisions need to be made essentially, if I understand it correctly, and I would defer to John McManus, the witness, on this for any details of the Clean Power Plan.

But my understanding is that after the rule comes out, from a timing perspective, and this is about all I understand, is that you got a year for the states to respond, they can ask for a two-year extension, so you've got three years out and then you'd be able to move on that in an another year. So you're about four years out where all decisions have to be made.

And so that's really what this was geared towards is helping people makes decisions during this timeframe and so that's the concern you have. Then you got to get the transmission done, right? So it takes multiple years to get it done.

So if you want something to begin compliance by 2022, you need to start well before 2022 with your decisions. And, quite frankly, even with your engineering design and stuff like that if you actually want it to happen by that time frame.

Q. And you could go back to Exhibit 2, the second page, subsection C, which about is a third of the way down says "One scenario included additional retirements." See that?

A. Yes.

Q. Is that scenario 5?

A. Yeah, this is the Clean Power Plan retirements, that's correct.

Q. So all these plants that are listed on page 2 and then over onto page 3, those are the plants you assumed would be retired under the Clean Power Plan?

A. Yes.

Q. And where did this list come from?

A. It came out of the initial work that EPA did, so it's associated with their, I believe it was called option 1 for regional compliance for 2020 year run. So they produced a list of generating plants that they thought would retire. And at the time when we did this analysis, that was the best information we had available to us in terms of what plants would retire. So we used that list from the EPA.

Q. So it's your testimony that there was an actual list that EPA issued saying these plants we think are going to retire?

A. Based on their analysis, yes.

Q. Have you seen such a list from EPA?

A. It's on their website. That's where we got it from.

Q. Are you referring to the IPM modeling?

A. Yes.

Q. To your knowledge did the IPM modeling identify specific units by name?

A. This is exactly from their list, as I understand it.

Q. Okay. Who provided you with this list?

A. So the list was made available to me through Scott Weaver who works in our Environmental Policy group I believe.

Q. And do you know how he obtained that list?
A. I believe he got it from the website.
Q. And how did he send it to you, via email?
A. Yeah, I think he did.
Q. And did you ever discuss the list with him?
A. I just asked him what it represented at the time and he said that represents what I just said to you, what EPA thinks would retire. And the units that they assumed would retire when they developed their targets for each of the states.
Q. And do you know how EPA made the list?
A. No. Again, we start getting into the 111(d) details, I would refer you to John McManus, Witness McManus.
Q. Yes. So you, have you personally done anything to verify that any of the units on this list are actually expected to retire under the Clean Power Plan?
A. No, I haven't done anything to verify that. I went with EPA's analysis.
Q. And if you look under Kentucky, the very first one is Big Sandy, see that?
A. Yes.

Q. 269 megawatt unit, that's the smaller of the two units there, correct?
A. That's correct.
Q. And that unit has just been converted to natural gas, hasn't it?
A. It's proposed to. I don't know if it's actually finished yet but they've proposed to convert it to natural gas, that's correct.
Q. Do you know if anyone at AEP expects to retire that unit?
A. I don't know. I'm not involved in those discussions.
Q. And if you turn over to page 3 under Ohio, Avon Lake, do you know who owns that?
A. I'm not sure. I believe it might be FirstEnergy but I'm not sure.
Q. Might it be General?
A. I don't know. It's just in that general area so I'm thinking FirstEnergy is up there but I really don't know.
Q. And do you know if that plant has been proposed to be converted to natural gas?
A. I have no idea. We did not do any assessment to look at conversions to natural gas.

Q. So these -- your study, am I correct, the modeling of the transmission impacts is based on PJM's 2019 regional transmission expansion plan?

A. Yes.

Q. And that plan, am I correct, assumes certain units stay in service and are running? Is that right?

A. Yeah. PJM will not retire a unit until they're told to retire the unit.

Q. And so all of these, all of the units in your Clean Power Plan 111(d) listed in the 2019 RTEP are assumed to be operating, correct?

A. I think that's generally correct. I'm trying to remember, there was some on the list that either had already been turned off or weren't modeled anymore, so they must have been shut down already. But generally that would be correct.

Q. So for the units that the RTEP assumed would still be operating you had to go in and just turn them off in the RTEP model?

A. That's correct.

Q. And the list of units for the 111(d) analysis, that's based on analysis of the draft or proposed Clean Power Plan; is that correct?

A. That's correct.
Q. So this list has not been updated to reflect the final Clean Power Plan.
A. Not that I'm aware of.
Q. So to your knowledge the list of units that may retire under the final Clean Power Plan could be different than the list you used in your analysis?
A. That's correct.
Q. And then if you look down at, if you turn to the next page of Exhibit 2, so page 3, subsection d. says "All transmission upgrades approved by PJM to mitigate the transmission reliability impacts due to deactivation of units affected by the MATS rule were included in the 2019 PJM RTEP model."
And then it says "The only modification AEP made to the case was deactivation of Conesville, Stuart, Zimmer, and Cardinal plants." Correct?
A. Yes.
Q. That's not true for case 5, correct? Or scenario 5?
A. Yeah, I think we were just referring to transmission upgrades here. We didn't make any

transmission changes, so I think that was the point here was we were just making sure people understood we did not make any changes to the transmission model.

Q. Okay, I see. Okay. So any transmission upgrades that were assumed in the 2019 PJM RTEP model were still assumed in your model.

A. That's correct.

Q. Now, if you turn over to the last page of Exhibit 2, we have amended response September 15, 2015. Says "The original answer misunderstood the question and this amended answer should replace the original answer," correct?

A. Okay.

Q. So the original answer includes, for example, the listing of the five scenarios, right?

A. Yeah.

Q. So the original answer with regards to the five scenarios that were modeled is still correct; is that right?

A. It's still accurate.

Q. And the original answer with regards to the list of 111(d) plants is still accurate?

A. That's still accurate.

Q. Is there anything in the original answer that is no longer accurate?

A. I think this was just clarification as to making sure they understood. Trying to remember now what the issue was.

MR. MILLER: Take your time.

Q. Yeah, take your time.

(Recess taken.)

A. So I think --

Q. I'm sorry, was that question actually on the record?

(Record read.)

A. No, I think for the most part it's all accurate. I think the amended response was just to provide additional clarification for some of the sections. So I could not identify anything at this time that was incorrect.

Q. Okay.

A. It's more just clarification I believe.

Q. So on the amended answer we should just strike that, the amended answer should replace the original answer?

A. Yeah. I don't think it should replace, it should augment it somehow.

Q. Okay. So we could say this amended answer should augment the original answer?

A. Yeah, I think that's fair.

MR. MILLER: Could we say "supplement"?

A. Yeah. Maybe that's a better word.

Q. Okay, that's fine.

So walk me through, you have scenario 5 which has PPA unit retirements and then also all these 111(d) retirements. You've identified I believe in your Transmission Assessment transmission upgrades and costs for the retirement of PPA units. Right?

A. Uh-huh.

Q. How did you break out these upgrades are for the PPA unit retirements rather than all the other retirements?

MR. MILLER: Shannon, can you point him to the specific?

Q. Sure, pages 9 to 10 on your Transmission Assessment. So let's say, for example, the first example which is Conesville Units 4, 5, and 6, you have a list of AEP upgrades, correct?

A. Uh-huh.

Q. And I guess to make sure the record's clear, is it your testimony that if Conesville Units 4, 5, and 6 alone were to retire, this $725 million figure is an estimate of transmission upgrades that may be needed?

A. Yes. If they retire in the context of including the 111(d), the Clean Power Plan that's in there and as part of the case, then yes.

Q. So if the Clean Power Plan units were not included, what upgrades would be -- may be needed for retirement at just Conesville 4, 5, 6?

A. I don't know. I didn't do that analysis.

Q. Same question with Cardinal Unit 1, you've got a total upgrade cost of $85 million, correct?

A. Yes.

Q. And that would be for retirement of Cardinal Unit 1 and all of the 111(d) units?

A. Yes.

Q. So do you have any knowledge as to what the upgrades would be needed for just retiring Cardinal Unit 1 would be?

A. No. Didn't look at that detail analysis.

Q. Flipping over to page 10, Stuart and Zimmer plants you haven identified upgrade costs for $240 million; is that right?

A. Yes.
Q. And that's a cost for upgrades if Stuart, Zimmer, and all the 111(d) plants retired?
A. Yes.
Q. And so do you know what upgrades would be needed if just Stuart and Zimmer retired and not the 111(d) units?
A. No.
Q. And then the final section here on page 10 says "Incremental upgrades to mitigate impacts of Cardinal, Stuart, and Conesville," and it identities $640 million; is that right?
A. That's correct.
Q. And so that $640 million figure, what does that represent?
A. So that's what happens if you do them all together. When you retire plants -- so if you looked at simply just the retirement of a single plant or single unit, you get one impact. But if you look at two plants together -- and if you look at another one by itself, you'd get another impact. But if you look at two together, the impact's going to be bigger. So there's a combined impact of all the units retiring and that's what that section represented.

Q. But that combined impact, is it just -- is the resulting upgrade cost 640 million or is it 640 million plus the 240 million and 85 million and 725 million?

A. Yes, it's the incremental piece above those others.

Q. So all of those go together --

A. Yes.

Q. -- for the impact of retirement of Stuart, Cardinal 1, Zimmer, and Conesville.

A. That's correct.

Q. Plus and that also includes the 111(d) units.

A. In the context of 111(d) retirements, yes.

Q. Do you know what the approximate cost would be if just Stuart, Cardinal 1, Zimmer, and Conesville retired and the 111(d) units continued operating?

A. No. Didn't do that analysis.

Q. And why did you not do any analysis of the units of the cost of transmission upgrades for retirement of just the PPA units without the 111(d) units?

A. Because it's our belief that the EPA

111(d), the Clean Power Plan, will move forward and our expectation is there will be generation retirements associated with that. So for us to ignore the combined affects of all that would ultimately give you the wrong answer in terms of what we think ultimately the transmission reinforcement should be.

So we've had this experience with MATS, we talked about a little earlier where we looked at our generating units, you get one number, FE looks at theirs, FirstEnergy looks at theirs, they get another number, but when you look at them together, it creates a much bigger problem on the grid.

We had hundreds of millions of dollars that we had to either advance or incremental spend simply due to the fact that FirstEnergy's units retired. And so when you do those analysis, you have to look at the combined affects of everything.

Clean Power Plan's going forward. The expectation, my understanding the expectation is there will be carbon regulation that will ultimately result in generating units retiring simply because they won't be economic to stay in service.

You have to look at the combined affect of that. Those two things are moving together at the same time. To try and separate those, you don't get the final answer, you don't get a real answer, you get something that's simply not accurate. So we felt it was important to put them together.

Q. And you don't consider yourself an expert on the Clean Power Plan, correct?

A. I do not.

Q. And you haven't personally evaluated what units may or may not retire under the Clean Power Plan.

A. I have not.

Q. And you also haven't personally evaluated when any units might retire under the Clean Power Plan?

A. No, I have not evaluated when. However, I am familiar with studies done by others who have looked at those types of things and suggest, and PJM is the most recent study on that where they've done an analysis.

So while I don't pretend to know all the details around peak's analysis, I do know they ran scenarios where they looked at significant retirements on their footprints. So, you know, we're going with that collective information that the expectation is there will be retirements, best available information I had at the time was EPA studies.

Q. And the PJM study you referred to, do you know what study that was?

A. They did an analysis at the request of the organization of PJM states.

Q. And when was that analysis?

A. They did it over the last -- trying to remember when they did -- the economic analysis came out. Within the last probably six months.

Q. So do you know if that was reflecting the proposed Clean Power Plan versus the final?

A. Proposed.

Q. Do you know of any analyses of generating unit retirements under the final Clean Power Plan?

A. I'm not aware of any right now.

Q. Would you consider PJM a credible source of analyzing what the impacts of the Clean Power Plan might be on the grid?

A. Sure.

Q. And do you -- of the $1.6 billion figure do you know what portion of that would be cost related to the reliability impacts of the retirement of the 111(d) units?

A. I didn't study that in this analysis, no.

Q. So there's no analysis of if the affiliate PPA unit stayed open and just the 111(d) units retired, you don't have any analysis of what the transmission impacts might be.

A. I do not.

Q. So I believe we discussed earlier that there were four other scenarios run besides the retirement of all the PPA units and the 111(d) units, correct?

A. Yes.

Q. And those other four scenarios, none of those involved 111(d) units retiring; is that right?

A. They did not.

Q. And are the results of those scenarios reported anywhere?

A. I believe we submitted them in a response to data request from Environmental Law. So that would have been this week I think we submitted those analyses. But the issue there was we didn't do the full detailed analysis for those scenarios. Those scenarios were done more for the planning team to try and understand how the model is going to react when you make large changes on the system.

So what they did was they built up -- this is discussed in the response we gave to the RFI from Environmental Law. They kind of built up a process where they looked at one and then they looked at the next one and looked at the next one and looked at them all just so they can get comfortable with what impacts were going to be so when they finally got to the scenario they were going to use, they would be able to develop solutions and recognize were there any issues along the way that didn't seem to make sense. So they just did that as they got to the end.

It was standard practice where if you've got big changes on a power flow, these things are somewhat sensitive at times and they can create nonconvergence issues, meaning the solutions, they won't solve. So they worked into the final solution. So that's what those other ones represent.

And we had that analysis done, someone asked for it so we handed that to them because we had it but it wasn't the complete analysis, we didn't do the full reliability analysis on that. But we did have output from that. But those were more for the engineers, the planners to develop, ultimately get to the final solution and help them understand what the impacts might be out there.

Q. So could you use the results of those --

MS. PETRUCCI: Before you go back on, Mr. Bradish, you were just fading in and out a little bit there. I don't know if you were moving relative to the microphone but if you could speak up just a little bit, thanks.

THE WITNESS: Yes. I was using my hands and I think I might have been blocking my mouth, sorry about that.

MS. PETRUCCI: Thanks.

Q. So have you ever looked at the results of those scenarios 1 through 4?

A. I haven't looked at those, no.

Q. Do you know if the results of the scenarios 1 through 4 could be used to determine what level of or what transmission upgrades might be needed just from retirements of the PPA units as opposed to the 111(d) units?

A. Not as I stand because they're not complete. Like I said, they didn't run the full set reliability test. So you can't use those results to draw conclusions like that.

Q. Okay. And who decided that those scenarios shouldn't be completed?

A. I don't think anybody decided that. I think they weren't considered scenarios where they ultimately developed in test solutions. Like I said, they were more for the planners to study and understand how the grid's going to respond so when they get to that final scenario, they would have a better feel for what's happening on the grid as a result.

Q. With regards to the fact that the transmission upgrades that you are identifying in your testimony reflect both the PPA units retiring and the 111(d) units retiring, did someone make the decision that you shouldn't look at just the PPA units retiring?

A. No, I don't think so. The decision we made, I made was to look at the PPA unit retirements in the context of 111(d) because it's happening and it's real. And so to do something different than that would not give us accurate results.

I think the team needed to do that, just like I said, so they could understand the process, understand what was happening on the grid as they went through the different scenarios. But, no, there was only one scenario that I wanted results from to develop solutions and that's the one we gave you.

Q. And so you were the one that made the decision that that would be the scenario to use.

A. Yes.

Q. So my understanding is that, and I guess if you want to turn to page 4 of the Transmission Assessment, the title here is Retirements and Dispatch - 2019 RTEP Model; is that right?

A. Yes.

Q. And this again reflects scenario 5?

A. Yes.

Q. So says 15,850 megawatts retired from the model; is that right?

A. Yes, it is.

Q. And so that's the amount of capacity you retired from what was included in PJM's 2019 RTEP model?

A. Yes. So let's be clear on that. So when the team looks at this, when we look at this, I should say, what this represents is how much the actual unit was dispatched in the model.

Q. Okay.

A. So it may not be the name plate capacity of the units themselves. So whatever was dispatched in the model, they were being very clear this is the amount in the model that we changed. So that's what they were trying to identify.

Q. Okay, makes sense.

(EXHIBITS WERE MARKED FOR IDENTIFICATION.)

Q. So you've been handed, Mr. Bradish, Sierra Club Exhibit 3, which is the company's response to ELPC interrogatory 3-002; is that correct?

A. Yes.

Q. And you are identified as the witness who prepared this answer; is that right?

A. Yes.

Q. And then Sierra Club Exhibit 4, which is Attachment 1 to ELPC interrogatory 3-002; is that right?

A. Yes.

Q. And that's a three-page attachment; is that right?

A. Yes, it is.

Q. And have you seen both of these documents?

A. Yes, I have.

Q. Did you prepare these documents?
A. Under my direction, yes.
Q. So Mr. Wilcox actually prepared them himself.
A. Yeah, he or his team.
Q. And you reviewed them before they were submitted?
A. Yes.
Q. So the request subsection f. says for Company's scenario 5, retirement of all plants plus those identified by EPA as impacted by the Clean Power Plan, please list each generating unit identified by EPA as impacted by the Clean Power Plan. Do you see that?
A. Yes.
Q. And your response on the very back page refers to ELPC interrogatory 3-002, Attachment 1.
A. Yes.
Q. And that's what's been marked as Sierra Club Exhibit 4, right?
A. Yes.
Q. So Sierra Club Exhibit 4, am I correct, identifies the units that you turned off in the -- in your modeling in comparison to what was in the 2019

RTEP model? Is that right?
A. Yes, those are the units we would have turned off, that's correct.
Q. So I'm curious, if you compare ELPC, well, Sierra Club Exhibit 4 to page 4 of Sierra Club Exhibit 1, the Transmission Assessment?
A. This one?
Q. Yes.
A. Page 1?
Q. Page 4.
A. Page 4.
Q. So looking at Sierra Club Exhibit 4, for example, you have Illinois as the very first state listed, right?
A. Right.
Q. And you have I assume that's megawatts, 6,058 megawatts? Very top.
A. Yeah. I'm not sure what that number represents.
Q. Okay. And do you know why that number is different than the number reported on page 4 of your Transmission Assessment for Illinois?
A. The thing on page 4 should have been a summation. That 6,000 took on a wrong number,

probably better to sum the actual columns. I'm not sure what the 6,000 actually represents.

Yeah, I don't know what the 6,000 represents. This is the list of units I think that was in the earlier list here and that we should have summed only those units. So I'm not sure what the 6,000 represents.

Q. Okay. How about for Indiana, the 1889?

A. Yeah, again, I'm not sure what that represents. So the list of the units is consistent with the list that we put in the response to you but for some reason I don't know what that 1889 represents.

Q. So you don't know if that was any sort of an input into the RTEP model?

A. No, that would not have been input into the RTEP model. I don't know what that number represents though.

Q. And but that number is inconsistent with what is on page 4 of the Transmission Assessment; is that right? For Indiana.

A. That number is not on page 4. The number on page 4 represents the sum of those individual ones and that number does not represent that.

Q. Okay. And so am I correct that would be the same answer with regards to the other states?

A. Yes. Don't know what that number represents.

Q. And do you know why -- let's see. So the Ohio on page 2 of attachment -- Sierra Club Exhibit 4 under Ohio you have listed Avon Lake, which I think we discussed earlier, Conesville, Hamilton, and Orrville, right?

A. Yes.

Q. But you don't have any of the other PPA units listed there.

A. Yeah, because Conesville was actually identified by the EPA as a unit potentially at risk for retirement in their analysis. In our analysis Conesville is a PPA unit. So it was removed from this list when we did the analysis. It was removed in the sense that it's not an EPA number anymore, it's a PPA unit now.

Q. Okay.

A. Because they did identify Conesville as at risk for retirement.

Q. I see.

And if you look down at the bottom of

page 3, so we have the AEP retirement, right? Listed there.

A. Yes.

Q. Now, I'm not a math expert but the total of those numbers is north of 5,000 megawatts, correct?

A. Yes.

Q. And over on page 4 of your Transmission Assessment you've got it identified as 4,036 megawatts.

A. Yes. Getting back to the earlier question that you asked about this, about those being capacity values, they're not. These represent the capacity ratings of the units. What we did then is we went into the model and turned it off. Whatever it was dispatched at the model, that's what those numbers add up to there on that list.

Q. Okay.

A. That's why the dispatch is in there, retirement and dispatch, because here's the units we retired, the dispatch amount, not that it was actually set to in the case, in the RTEP case is what those numbers represent.

Q. Okay.

A. So they don't represent, that does not represent the capacity of unit. This does represent the capacity of the unit.

Q. Could that be the explanation for why the state numbers in Sierra Club Exhibit 4 are higher than the numbers reported on page 4 of the Transmission Assessment?

A. I don't know what the reason is.

Q. Okay.

A. I just do not know why.

Q. Okay. Fair enough.

A. The important information is the unit listed and the fact that we turned it off. What that sum represents or what that is, I don't know. But the list that we've got here that says the units we turned off is consistent with the list we sent you in the interrogatory earlier. So I think that's the important part to focus on.

Q. Okay. Now, so in terms of removing units from the 2019 PJM RTEP model, nothing else is removed, correct? Outside of the 111(d) units and the PPA units.

A. Yeah, we didn't change the transmission system.

Q. And you didn't remove any other units?
A. No.
Q. Okay. Now, the RTEP model, am I right that assumes that certain proposed units would -- that have interconnection agreements and service date before June 1, 2019, would be included in the RTEP?
A. That's correct.
Q. Are there any other proposed units that would be included in the 2019 RTEP?
A. Not sure on that. I think what PJM does is once they get to an FSA stage, once they get that agreement signed I believe they put it into the RTEP. Whether or not they put in units that have an in-service date beyond 2019 in their case even though it's not supposed to go in before 2019, I don't think so. But for the most part I think the stuff is supposed to be in place by 2019.
Q. So units that are supposed to be in place by June 1, 2019, and that have either an interconnection agreement or a facility support -- services agreement, those would all be included in the RTEP model?
A. I believe so.
(EXHIBIT WAS MARKED FOR IDENTIFICATION.)

Q. All right, you have been handed, Mr. Bradish, Sierra Club Exhibit 5, which is the company's response to Sierra Club interrogatory 5-119; is that right?

A. Yes.

Q. And so -- and I'm sorry, have you seen this document before?

A. Yes.

Q. And you are identified as the preparer of this document?

A. Yes.

Q. And did you draft this document, this response?

A. It was done in my direction, yes.

Q. By Mr. Wilcox?

A. Yes. Or his team.

Q. And so subsection a. says, well, "For each of the five different scenarios identified in interrogatory 2-070, identify each specific new generating unit on the 'PJM generation interconnection queue' that was assumed to be added to the system impact study."

A. Right.

Q. And then your response discusses, I guess, how you determined what units to add; is that right?

A. Yes.

Q. And says "A significant amount of FSA units were already modeled online in the 2019 RTEP case"; is that right?

A. Uh-huh.

Q. And then "Generators with capacity less than 5 megawatts totaling 200 megawatts were not modeled...," right?

A. Uh-huh.

Q. So when you say those were not modeled, do you mean PJM did not include them in the RTEP or that you decided to remove them from the RTEP?

A. I think it's neither of those. I think what happened was they were in there but we didn't turn them on. We didn't use them in our analysis. So again, if they're an FSA unit, my understanding is PJM will put them in the case, but we just didn't turn them on. We didn't use them in this analysis.

Q. Do you know if PJM would turn them on in their analysis?

A. I think PJM turns on everything they have.

Q. And why did you not turn them on?

A. We did not need all of the FSA units for this analysis. So we decided, as it says here, that we looked at units that had been stalled for more than three years and have transmission upgrade costs greater than 25 million, we simply did not turn them on.

Q. But that's a different set than the generation -- generators with less than 5 million megawatts.

A. It is.

Q. So when you're saying you didn't need them, what do you mean you didn't need them?

A. The amount of generation we're retiring did not require us to use all of the FSA generation that was in the queue.

Q. And that's because you were attempting to replace the amount of generation retiring one for one?

A. Yes.

Q. So then you also say in this response "...nuclear uprates totaling 1600 megawatts (including North Anna Unit 3 scheduled for 2024) was not considered assuming these uprates may not get the required regulatory approval by 2019." See that?

A. Yes.

Q. So those are 1600 megawatts of nuclear uprates that PJM had included in the 2019 RTEP case; is that right?

A. I'm not sure if they're in the case or not. They might have been, but again, they're not scheduled till 2024 so we didn't use them.

Might also say in that one, I believe I recall on that one I asked them to check on that unit to make sure and when we went to Dominion's website what we found there is Dominion has no plans, meaning their words, they have no plans to build this unit at this time.

And given that it's probably going to take ten years or so to build a plant like that, it would not fit within the timeframe we're looking at so that didn't make any sense for us to include it.

Q. But that and then North Anna Unit 3 is just one of the units involved in the nuclear uprates totaling 1600 megawatts, correct?

A. Yes.

Q. So there were other uprates that you removed from the RTEP?

A. I think there were other uprates that we simply did not turn on.

Q. Do you recall which those were?
A. I do not know which ones they were.
Q. Do you know why those you removed?
A. What we said, we didn't feel they would move forward by 2019.
Q. And did you personally verify whether those would be expected to move forward by 2019?
A. I did not personally verify.
Q. Do you know who did?
A. My staff would have looked at that.
Q. And is that identified anywhere in writing which nuclear units were removed?
A. It would have been whatever was listed in the PJM queue at the time, those would have been the ones.
Q. So if it was in the PJM queue with an FSA or an ISA?
A. ISA.
Q. Or ICA?
A. ISA.
Q. PJM would have included them and that's how we can determine which ones that you removed.
A. Yeah, but usually PJM would include in their analysis anything that would have an in-service

date beyond 2019. So even if it is marked as an FSA, they may -- I'd have to verify this, I'm just not sure on this part of the answer whether they actually include those in the model itself and just don't turn them on and use them in the analysis or didn't put them in the model, I just don't recall.

Q. So for the nuclear uprates at some point between when PJM made its list of units to put into the RTEP and when you did your analysis, those units switched from being expected to be in service by 2019 to expected to be in service sometime later?

A. I don't know if they were expected to be in service by 2019 or not. We've listed North Anna was scheduled for 2024. So I don't know, I don't recall when the nuclear uprates were scheduled to be in service. I just didn't use them.

Q. And then you also state that generation that has been stalled for more than three years and transmission upgrades cost greater than 25 million were not included.

A. That's correct.

Q. And do you know how many megawatts or units those are?

A. I don't recall that, what that actual amount was.

Q. Do you have a general sense, are we talking a hundred megawatts or 5,000?

A. I don't think it's -- I don't want to speculate. I just don't remember what that number is.

Q. Did you review that list personally?

A. Not personally.

Q. So who made the decision which units we were to remove under that category?

A. So the criteria of more than three years and transmission upgrades greater than 25 million was my decision. The implementation of that decision was done by my staff.

Q. And do you know, is there a list of what units they removed anywhere?

A. That they didn't turn on? I don't think we created that list.

Q. And so you've got the 2019 PJM RTEP and from that you removed your PPA units, the 111(d) units, and then the three sets of units that were not turned on that we were just discussing, correct?

MR. MILLER: That's kind of a compound question.

A. Yeah, could you break it down by piece and I'll answer "no" to what you said.

Q. So you got the PJM 2019 RTEP from PJM, correct?

A. Yes, got that.

Q. And that's the base for your transmission modeling, correct?

A. Yes.

Q. And then you removed from that the PPA units.

A. Yes.

Q. This is for scenario 5.

A. Yes.

Q. Then you removed from it the 111(d) units.

A. Yes.

Q. Then you removed from it generators with capacity of less than 5 megawatts.

A. No. So I would characterize that differently.

Q. Okay.

A. We didn't turn them on because they're going to be modeled in the case but they're not going to be turned on.

Q. So do they -- if they are not turned on, do they play any role in the modeling?

A. My understanding is that they will, for certain of the analyses PJM will use the FSA units. Like for a gen delivery and stuff like that they will use the FSA units. But there's restrictions on how they will use those and what they will let them -- how they will let them participate and what they won't let them do.

And I don't know all the details of it, but my understanding in general is they'll allow FSA units to possibly create problems, they won't let the FSA units resolve problems. But so that then forms -- informs them on their study but what they'll typically do in that situation then is they'll go back and they'll do, you know, they'll recognize that but they won't necessarily take any action on it because it's driven by an FSA unit that doesn't have a commercial -- that's doesn't have -- not in service yet. They don't want to necessarily take action on that.

So it's more of an informed study for them and they continue to look at that and as those units move forward, PJM tracks them, and once they go into service, then they're treated as full capacity in their analysis.

So it's FSA units are treated a little differently than regular generation, online generation.

Q. So if you have -- if you are running a load flow model based on the 2019 RTEP and you have a unit that is proposed, does that unit, if it's included in the RTEP, does the fact -- does that unit impact the results of your modeling in any way?

A. If the unit is online, it certainly does impact the results. Meaning if it's modeled with an output greater than zero.

Q. Okay. And the units that you turned off in the model, they would have -- in the PJM RTEP model, they would have initially been turned on at something higher than zero, correct?

A. Yes.

Q. So by turning them off they no longer have an impact on the results of the modeling, correct?

A. Oh, yes, they do. It's the change in state, right? So if they've never been on, then this has never been an issue. Now you got a unit that was on, now all of a sudden you turn it off. So you've changed power flow as a result of that.

So the FSA units are modeled at zero, so if they're modeled at zero and they're never on in any situation, then their impact is zero, there's no impact. But if you have one that's on and you turn it off or if you have one that's off and you turn it on, you've made a change in the power flows and that changes your results.

Q. Okay. So that -- and that change in results could result in identifying additional transmission upgrades that would be needed?

A. Yes.

Q. And so the generators with capacity of less than 5 megawatts totaling 200 megawatts total, that you turn off.

A. We just didn't turn them on.

Q. You just didn't turn them on.

A. They were set to zero in the case and we didn't use them.

Q. So they were already set to zero. So that decision, it's your opinion, would have no impact on the modeling results, correct?

A. Yes. And that's part of the reasons we didn't turn them off because they're 5 megawatts or less, they're scattered throughout the model.

Wouldn't feel that at the end of the day they had meaningful impact on the results so we didn't use them.

Q. Okay. Let's go to the nuclear uprates totaling 1600 megawatts. Would those in the model initially that you got from PJM, were they turned on?

A. No.

Q. So those were off and you just left them off.

A. Yes.

Q. And then the generation that is stalled for more than three years and have transmission upgrade costs greater than 25 million, were those turned on in the model?

A. Some of them had already been on.

Q. Okay.

A. So the other step is that PJM, sometimes they have to balance load and supply and so if they don't have enough supply, they go and they start turning on the ISA units and the FSA units. I don't recall if, how many if the FSA units actually were turned on. But I guess I'm just not sure. It is possible that they might have been turned on but I'm not sure whether they were turned on or not.

Q. But if any of them were turned on, you turned those off.

A. No, we left them on.

Q. Okay. So I'm sorry, the generation that has been stalled for more than three years in transmission upgrades and cost greater than 25 million.

A. Yeah, those all had to get turned on.

Q. So those you're saying in the PJM RTEP were off already?

A. Yeah.

Q. All of those were off.

A. All of those were off, we had to turn them on.

Q. And you just didn't turn them on.

A. We did the ones that met that requirement -- I'm sorry, that met the requirement, they were not included. I'm sorry, I got that backwards. Sorry.

If they were stalled for more than three years and their costs were more than 25 million, we did not turn them on.

Q. So we're clear, in the PJM RTEP they were not turned on.

A. That's correct.

Q. Okay. So were there any units in the PJM 2019 RTEP outside of the PPA units and the 111(d) units that were turned on in the 2019 RTEP that you turned off?

A. No.

Q. Okay. So you have the units that were removed, now let's go to the units that were added in. If you could go to page 4 of the Transmission Assessment.

A. Okay. Yes.

Q. So we now have two-thirds of the way down the page says "PJM interconnection queue projects in facility study stage and with signed IAs dispatched to make up for retired generation." Do you see that?

A. Yes.

Q. What is a signed IA?

A. Interconnection agreement. They must have abbreviated that. It's ISA or IA.

Q. So they've abbreviated from the abbreviation.

A. I think so.

Q. And then it says "14,448 megawatts of capacity projects dispatched"; is that right?

A. Yes.
Q. And 880 megawatts of energy dispatched?
A. Yes.
Q. What's the difference between a capacity project and an energy project?
A. Wind. So wind unit would have a name plate rating of, say, a thousand megawatts but it's only treated as 130 megawatts capacity, 13 percent of its name plate I believe is the right answer for PJM. So those are more than likely wind and solar. I don't think there was a lot of solar in the queue.
Solar I think we use, PJM uses 38 percent of named plate capacity for solar. So, yeah, they get modeled in a peak case at their capacity value.
Q. And that's the energy projects, right?
A. Yeah.
Q. So the 880 megawatts, is that the capacity value or the name plate?
A. That's actually dispatched, I don't think it's the name plate.
Q. And so these are units that you took the PJM RTEP files and you turned on these units?
A. Yes.
Q. So these are units that were already in

the RTEP but turned off?
A. Yes.
Q. And you turned on units that had either an FSA or an ISA?
A. Yes.
Q. And that was only in scenario 5 that you did that, correct?
A. Yes.
Q. So scenarios 1 through 4 did you do any of that?
A. Yeah, in the answer we gave to the Environmental Law they asked us when we did -- when they looked at the preliminary analysis when they looked at just the Conesville unit or Conesville units, or the Cardinal unit, when we modeled those offline we added in capacity to offset them. And so those were given in the responses to Environmental Law.
Q. Are you referring there to Sierra Club Exhibit 3?
A. That's correct.
Q. And so in your responses to Sierra Club Exhibit 3 starting with subsection a. at the bottom of page 2, so you say "The following IPPs were

turned" I assume you mean turned on?

A. Yes.

Q. "...to make up for the retirement of Conesville units in scenario 1."

A. Yeah.

Q. And then you've identified various interconnection queue project numbers.

A. Yes.

Q. And those correlate with what was added in?

A. Yes.

Q. Okay. And then that's the same for the other scenarios?

A. Yes.

(EXHIBIT WAS MARKED FOR IDENTIFICATION.)

Q. I've handed you a document labeled Sierra Club Exhibit 6, and it's the PJM Generation Queues Active; is that correct?

A. That's what it says, yes.

Q. And I assume you haven't seen this specific document but does this --

A. I have not.

Q. Does this appear to be a printout of the website of PJM interconnection queues?

A. It does have that appearance.
Q. Great. Do you regularly visit that website?
A. I do not.
Q. You do not, okay.
Do you know in your responses on Sierra Club Exhibit 3 you have a link; is that right? To PJM interconnection queue.
A. 3.
Q. Starting on page 3.
A. A link to the generation interconnection, yes.
Q. Do you know, would the printout that I gave you in Sierra Club Exhibit 6, would that be what's linked?
A. I believe it is.
Q. Okay. Have you ever visited the PJM interconnection queue or generation queue website?
A. Maybe one time I've been there. But, no, I've never gone into the details here like this.
Q. So in terms of identifying in your responses in Sierra Club Exhibit 3 the project numbers, did you have any role in that?
A. No, I did not.

Q. So those were identified by Mr. Wilcox?
A. Yes, and his staff.
Q. So did you ever review which PJM generation interconnection queue projects were added into any of the scenarios?
A. No, I did not review the details.
Q. Would you accept that the PJM interconnection generation queue listing would likely be accurate on their website?
A. I can't speak to its accuracy, but.
MR. MILLER: Objection. That calls for speculation on his part whether it's accurate.
A. I mean, it's subject to whatever input errors are and stuff like that. But it's their queue, it's what they have.
Q. Do you have any reason to question the veracity of their queue?
A. No. No.
Q. So if you're looking at Sierra Club Exhibit 3, and I just want to make sure I'm connecting these up correctly.
A. I understand.
Q. If you look at let's say the response to subpart d., which is at the bottom of page 3, so you

say "The following IPPs were turned," once again I assume you mean "on," correct?

A. Copy and paste, it's dangerous.

Q. "...to make up for the retirement of Conesville, Cardinal 1, Stuart, and Zimmer units in scenario 4," correct?

A. Yes.

Q. And then there's a long list of projects.

A. Yes.

Q. And so let's just take the first one, queue 39.

A. Okay.

Q. So if you look at Sierra Club Exhibit 6 and you turn to page 21 of 49, that would be there's a queue 39 there; is that correct?

A. Uh-huh.

Q. And that says Kewanee 138 kV; is that right?

A. Uh-huh.

Q. And it has an in-service date of quarter 4 of 2016.

A. Yep.

Q. And that's a project in Illinois?

A. Yes.

Q. So would that be the project you're referring to in subsection d of Sierra Club Exhibit 3?

A. I think that would be -- that's how you would interpret that, yes.

Q. And do you know how the specific projects to turn on were decided?

A. For these analysis?

Q. Yes.

A. I don't. I don't know what process -- I don't recall what process was used because at the end of the day we were not going to use that to develop solutions, so I don't know really how they decided what subset then to use for this, for these analyses.

Q. How about for scenario 5?

A. For scenario 5 it was all the ones we had listed in that -- we had a separate thing that we sent out that said here's all the things that we used.

Q. And do you know how that was selected? How that list was selected?

A. What we just went through, it was the FSA list and it's those units that have not been stalled for three years and not cost greater than 25 million,

those were the units that should have been in that list.
Q. So all of those units?
A. Yes.
Q. As of August of 2014?
A. Yes.
(EXHIBIT WAS MARKED FOR IDENTIFICATION.)
Q. You've been handed Exhibit Sierra Club 7 which is the response to Sierra Club RPD-2-071.
A. Uh-huh.
Q. Is that correct?
A. Uh-huh.
Q. And you're identified as the preparer of this response; is that correct?
A. Yes.
Q. Have you seen this document before?
A. Yes.
Q. And then there's an attachment that is a listing of appears to be 101 entries; is that right?
A. Yeah.
Q. And there's no identification on this document of specifically what it is; is that right?
A. Meaning there's no what?
Q. Like, no title to the document.

A. No, I don't see a title.

Q. Is this the listing of projects that were added to or turned on in the 2019 RTEP in scenario 5?

A. Let me verify that.

Yes, that's my understanding.

Q. Okay. And have you ever seen this list before?

A. Yes; when we prepared it to be sent.

Q. So you had some role in preparing this list?

A. I just reviewed it and asked what it represented.

Q. And so again, if you turn to the list, there's a header that says Name and the name is a letter and some numbers; is that right?

A. Yes.

Q. Are those the PJM interconnection queue numbers?

A. Yes, that's my understanding, yes.

Q. So those numbers you can match up with the queue numbers on Sierra Club Exhibit 6; is that right?

A. Yes.

Q. So if we take, for example, the second

listing on the table that's on Sierra Club Exhibit 7, it says R-011; is that right?
A. The second one, yes.
Q. And if you go to page 21 of Exhibit 6, the second-to-last listing is R-11.
A. Yes.
Q. And those appear to be the same project; is that right?
A. Yes.
Q. And do you know the projects listed here in Sierra Club Exhibit 7, the attachment, would this be all of the units that have a facility study or signed interconnection agreement in PJM?
A. These should have been the ones that met that criteria that have not been stalled for more than three years and less than 25 million in reinforcements needed for transmission. So that's the criteria. So if you meet that criteria, we'll include you. If you don't meet that criteria, we won't include you.
Q. Okay. So to your knowledge there's not additional proposed units in the queue that would meet that criteria that were not included; is that right?

A. So this, I believe these are all FSA units I believe. So it probably does not -- I'm not sure if it includes the ISA units or not, that's where I'm not sure. These might be all FSA units. So I don't recall now.

Q. Okay.

A. But the ISA, these are the ones that we would have turned on though.

Q. But there may be other ones that fit the criteria that you didn't turn on.

A. No, I don't think so. I think these are the ones that fit that criteria, we turned them on.

Q. So am I correct you were trying to do one-for-one replacement of the assumed retirement generation?

A. Yes.

Q. And on page 4 of your Transmission Assessment, Sierra Club Exhibit 1, you identified 15,850 megawatts retired from the model; is that right?

A. That's what it says, yes.

Q. And if you look at the attachments to Sierra Club Exhibit 7, it's at a grand total of 15,328 megawatts?

A. Uh-huh.

Q. So you're about 500 megawatts short of the replacement one for one, right?

A. Yeah, those two numbers aren't the same. That's right.

Q. Do you know why it wasn't an exact one-for-one replacement?

A. I don't. I don't know why those numbers are different.

Q. Do you know if that would affect the outcome, the fact that you didn't, potentially didn't fully replace one for one?

MR. MILLER: Affect the outcome of what?

Q. The outcome of the modeling. The modeling results in terms of what transmission upgrades might be needed.

A. I don't think it would have a major impact on the results. But I don't know why they're different.

Q. Would you need to rerun the model with a one-for-one replacement to know why the results were different?

A. I'd have to know why those numbers were different first. If these were different. I think the results will, in terms of the ultimate we got to the solutions I think would be fairly consistent with the results we've already got.

Q. Why do you think that?

A. Because of the nature of the problems we had on our system and where the problems were. The solutions where you lost Conesville, you create a big hole in your system, you used -- we repurposed the outlets from that plant and used the HV system to support it. Same thing with the Stuart and Zimmer results, Cardinal results.

So I'm not thinking it would change the outcome substantially, so yeah, I don't think I'd recommend rerunning anything at this point for that change.

Q. Would the location of the new generation that you've turned on affect the results of your modeling?

A. Yes. Location matters.

Q. So looking at page 7 of your Transmission Assessment, it looks like -- it's not the easiest map to read, however, am I correct that many of these projects are in or near Ohio?

A. Yes.

Q. And if you were to add more new generation in Ohio, could that help reduce the transmission upgrades you would need in the state?
A. It could help or hurt.
Q. How would it hurt?
A. Location matters. If you put it in the wrong spot, you could actually hurt things.
Q. Okay. But you could also help things, correct?
A. Yes. It could be either.
Q. And how could it hurt things?
A. Well, if you put it in a situation where there's already heavily loaded facilities and then more generation comes to that area, you're just going to overload those facilities.
Q. You did not do a load deliverability study; is that correct?
A. That's correct.
Q. So you don't know, or do you know, are there load deliverability issues in this region of Ohio where you're proposing to -- where you're finding that you need to add transmission upgrades?
A. We have not done that analysis.
Q. So if you were to add some more generation

to Ohio, you don't know how that would affect load deliverability.

A. I don't.

Q. And why did you not do load deliverability analysis?

A. Up until now that has not been an issue for the AEP zone. We've had -- we haven't had restrictions on how much capacity we actually use in our system because we've been long generation. As we go forward as more generation retires, as our zone becomes shorter, meaning it's got more load than generation, then the likelihood of having a load deliverability analysis done and finding problems with this increases.

So we just historically haven't had that issue for our zone because we've had ample generation. So we haven't run that analysis and I don't know, I'd have to go look at the ultimate supply/demand balance to figure whether or not you need to run that analysis. It's a little bit more involved.

Q. And so is that what you would need to do to determine whether adding additional generation in, say, the central region of Ohio would create more problems rather than --

A. It's just one up. You'd have to do the full set of analysis we've already done and just another one you would do on top of that to figure out what the impacts are.

Q. So looking at page 4 of the Transmission Assessment, you say that you're assuming in the model that 4761.8 megawatts of generation retires in Ohio, correct?

A. Yes. So that again must have dispatched the case.

Q. And then looking at the attachments to Sierra Club Exhibit 7, which is the new generation you put into the model, correct?

A. Right.

Q. For Ohio you've added in 2124.8 megawatts; is that right?

A. Yes.

Q. So if the actual amount of new generation in the queue that had an FSA or an ISA in Ohio were higher than 2124.8, do you know whether that would help reduce transmission impacts you've identified in Ohio?

A. I think it would be location dependent.

So it matters where. And so that's the biggest challenge. Location matters. So until you know what the location is and what the capabilities are of that unit, then you can figure out what that impact would be. So it could help or hurt; again, if you put it in the wrong spot, you could actually do harm.

Q. And when a proposed project does an interconnection agreement, does PJM study whether it's going to help or hurt the system?

A. It does.

Q. So if a plant has an interconnection agreement, is it safe to say that the PJM has already determined that either it won't harm the system or if it will, they've determined other projects need to occur to address that?

A. Only for the conditions they modeled. So PJM did not do that for the scenario where the PPA units are out.

Q. Okay.

A. So they would have to go back and look at from that perspective. So their model that the PPA units are on then they don't know what the effect would be.

Q. And are you aware of the proposed Carroll

County natural gas plant?

A. I am.

Q. And do you know, does that plant now have an interconnection agreement?

A. I don't know what its status is.

Q. Do you know if it was added into your -- if you added it into the 2019 RTEP model?

A. I don't believe so.

Q. You believe you did?

A. I don't think we added it in.

Q. Do you know what the impact would be if you had added that in?

A. No, I don't, because I haven't assessed it so I couldn't speak to that.

Q. Okay. Is it your understanding that you, if it -- assuming it -- let's just assume it does have an interconnection agreement, would PJM include it in its next RTEP?

A. Yes.

Q. And it would include it as a unit that's turned on?

A. If it has an ISA, I believe so.

Q. And are you aware of the Oregon, proposed Oregon Clean Energy Center?

A. Yes.

Q. And to your knowledge was that included in your modeling?

A. No, it was not.

Q. And do you know how that, if you did include that, would that impact your results?

A. Same answer I gave you before.

Q. Okay.

A. It could hurt or it could help.

Q. Okay.

A. I think that one's further removed from our system, if I recall. So it has less of an impact but still have an impact one way or another.

Q. And you simply don't know unless you actually did the model.

A. That's right.

Q. And is that, are you aware of the Middletown proposed natural gas plant?

A. I am.

Q. Is that the same?

A. Same type of discussion, yes.

Q. So you wouldn't know how it would impact the analysis until you did it.

A. That's right.

Q. And one more, Lordstown?
A. Yes.
Q. You're aware of that?
A. I am.
Q. And once again, you wouldn't know how that would impact your analysis unless you actually did it.
A. That's correct.
Q. And just to make sure, neither Lordstown nor Middletown were included in your models?
A. That's correct.
Q. And then you -- so on page 8 of your Transmission Assessment for the various AEP upgrades that you've identified there you've identified planning costs; is that right?
A. That's correct.
Q. How did you determine those planning costs?
A. We use kind of per-unit costs when we do these planning assessments. So we have kind of here is what a typical number would look like to do certain things.
Q. And what's the source of the per-unit costs?

A. Just our historical experience with billing transmission.
Q. So your own internal numbers?
A. Yes.
Q. So you didn't use numbers that, for example, have been filed with FERC.
A. Well, they're based on actual projects, so. Project costs would eventually have been filed with FERC but it's the list of costs by themselves that's ever been filed with FERC.
Q. And have your cost assumptions been produced in discovery in this proceeding to your knowledge?
A. I don't recall if we did or not.
Q. So let's just take, say, the new project A, the new 345/138 kV in near Philo. $15 million planning costs.
A. Yes.
Q. So I guess walk me through how you would do that math.
A. Yeah. So we would have for a new 345/138 kV station we would have a planning estimate that's $50 million as shown here. Planning estimate involves the transformer and whether or not you're

going to spare the transformer, in this case for 345/138 we could not include a spare. The actual configuration of the station, the layout of the station, the breaker configuration, the land cost, what it would take to bring the transmission line work associated with bringing transmission lines into the station.

It would involve the control house, communication facilities, protection facilities, anything that is involved with development of that new station. So that's how we kind of come up with these per-unit, if you will, costs for these types of things.

Q. So project A is a new substation?

A. Yeah, essentially going to be a new substation.

Q. And project B, is that a line, transmission line?

A. No, that's a substation.

Q. Oh, that's also a substation. How about project C?

A. Project C involved a variety of things, as indicated. So there's some lines, 138 kV lines, we looked at reconductor. There's things called sag studies. Basically what we do with sag studies, we assess the rating of the line.

The rating on the line we have may be below what we would think from what the actual thermal capability of the equipment would be so we go out and look to see if there's anything underneath the line that's preventing this thing from going to its maximum operating temperature. So we make sure there's nothing underneath it.

If there is, sometimes you have to do regrading, knock down a hill, or someone built a house underneath it by accident or something like that, those types of things.

And then terminal equipment is just that, equipment you use to connect facilities in the stations, stuff like that.

So we had a variety of those that we had to upgrade or replace or look at. Sag study is an initial study and if you find a problem, you have to fix the problem. So those involved -- that was involved in item C.

And again, there's standard things for reconductoring and for 138 I think it's a million dollars a mile. For sag studies we would have used an estimate of how much it cost per mile, I'm not sure. It's not a big number, it's $5,000 or something like that. Terminal equipment I think what it is, could be $2 million to address terminal equipment issues. So it's those types of numbers that we would look at based on what needs to get done.

Q. So you haven't done those sag studies, correct?

A. No, the sag studies have not been done.

Q. And how did you decide on reconductoring rather than replacing the line?

A. Reconductor is your go-to because it's the lowest cost. So we would look to do that first if we can. Reconductoring means putting a bigger conductor so you have to look to make sure the foundation's okay, the towers can handle it, the insulation is good. Lot of analysis to do if you decide whether to reconduct the works or if you have to actually rebuild it.

Q. And do transmission lines after a certain age need to be reconductored just in general?

A. Yeah. I mean, eventually lines get old enough that the materials begin to wear out, yeah.

You look to assess that and decide whether or not you want to reconductor or not or rebuild. Towers fail, foundations get deteriorated, stuff like that.

Q. Do you know with any of the upgrades that you've identified here on page 8 were any of those lines that may need to be reconductored or rebuilt anyway?

A. I don't think we did any of that assessment.

Q. So you simply don't know if these are lines that three years from now you'll have to replace them anyway.

A. Right.

Q. Do you know the age of any of these lines?

A. I don't.

Q. Is there, like, an expected life for a line, 138 kV line, every 30 years you have to replace it?

A. No, there's no expected life. Depending on what type of standards it was built to to begin with, and number two, what type of basically operating experience it's had. If it's -- just depends. So there's no real, you know, 50 years, boom, you're gone type stuff.

We have lines that are up to 80 to 90 years olds on our system. So it depends in terms of what materials it was made of, what standards it was built to, and what type of experiences it's had during its life.

Q. Is there an expected life for purposes of depreciating cost of it?

A. There is a depreciation schedule and I don't recall what that is off the top of my head.

Q. Are you involved in kind of figuring out how you're going to depreciate transmission investment?

A. No.

Q. Who does that?

A. Accounting group does that.

Q. So project D or upgrade D, Clifty Creek, is that a reconductoring?

A. I believe that is a reconductor.

Q. And then project E, what is that?

A. So that is dynamic, SVC means static var compensator, 250 MVar is mega var. It's the unit of, well, the units associated with reactive power. Million voltage reactive. So that's just dynamic support we need in Columbus because we're losing the dynamic support from Conesville, reactive power support that helps prop up voltages. So we're looking for dynamic source.

Q. So what is that?

A. It provides reactive power. It's very much necessary to maintain voltages, both magnitude of voltage and quite frankly, stability in the area.

Q. I guess I mean physically what is it?

A. It would fit in a station, it's a device. It's a combination of capacitors and reactors all tied together through some power electronics. But it sits within a station.

Q. And then project F is the Axton-Joshua Falls/Clover 765 kV.

A. Yes, so it's a line that would run from Axton to Joshua Falls.

Q. And that's a new line?

A. Yes.

Q. And then the next one down G, is that also a new line?

A. It's both a line and a station. So the Adkins 765/345 kV is a station, and Don Marquis to Adkins is a new line that would run from our 765 station over to that new Adkins station.

Q. And Beaver Creek, that's project H.
A. Yeah, it's a new 765/138 kV station.
Q. So no lines involved in that one.
A. No.
Q. And then capacitor banks in Eastern Ohio.
A. Yeah, so there's again, because we're losing the reactive support of the plants, there's a need to again support the voltages, so capacitors in this case they're static devices, meaning you don't have dynamic control of them, you can't change the output of the device, it's either on or it's off. So we've proposed those in several locations, so those sit within the station.
Q. And then Stuart 765/345 kV.
A. Yeah, new station.
Q. Okay.
A. Keep in mind, with all these new stations there is line work because you do have to move, pull the lines into the station. So there's, like I said when I gave you that cost estimate number, includes line work with those.
Q. And so for the planning costs for all of these would you agree they're just kind of rough estimates?

A. Yeah, planning estimates, yes.
Q. So there's no like --
A. There's been no detailed engineering with this. They are based on our experience of building transmission.
Q. And so once you do the -- if you were to do the detailed engineering cost, could be higher or lower --
A. Yes.
Q. -- than your planning costs?
A. Yes.
Q. And how, for the 765 kV lines how did you decide that's needed as opposed to other smaller lines?
A. That was geared to fit the problem that we were seeing on our system. So the solutions here proposed are really geared based on the magnitude of the problem you're seeing and the magnitude of the problem we're seeing was fairly substantial.
There was significant voltage issues, low voltage, voltage collapse issues, overloaded line. There's some nonconvergence problems. The case wasn't solved because the problem was so bad. And so the 765 kV line, Axton-Joshua Falls/Clover line was

proposed to address a lot of those issues. So it's a big problem so it required a fairly good size solution.

The other one, the other 765 kV line is because we lose Conesville and the power from Conesville comes from north of Columbus, northeast of Columbus, and when you lose that power, the remaining power to feed Columbus and Central Ohio area comes now from the south. And so that whole southern path that leads into the Greater Columbus area picks up a lot of that flow.

So what we've done is we've proved our ability to move that power from the south into the Columbus area with the line and then the station is where we terminate that line to bring it down into the 345 and then eventually down into the 138.

Q. And if you were to, instead of retiring one of the PPA units if you were to instead replace it with, say, a natural gas combined cycle unit, would that address the reliability impacts from retirement?

A. Yes. Well, let me qualify that. If you replace it with similar sized.

Q. Similar sized.

A. Again, if we go for the megawatt for megawatt, then yeah, they would resolve the reliability issues.

Q. And how about if you were to repower one of the coal boilers with gas, would that also address the reliability issues?

A. Yes, again, if it's the same size, same capabilities, exactly.

Q. And with regards to Conesville you haven't done any analysis of the reliability impacts of retiring, say, only Conesville Unit 4, correct?

A. That's correct.

Q. Or any subset of Conesville units.

A. That's correct.

Q. The 2019 PJM RTEP case uses the PJM's 2014 load forecast; is that right?

A. Yes. So it would have been what we call, yeah, 2014 series, meaning it was built in 2014. So, yeah, it would have been that load forecast.

Q. And would you agree that load plays a role in what transmission impacts might occur from a retirement?

A. Yes.

Q. So if you have higher load, you might have greater impacts?

A. Yeah, I think that's fair to say.

Q. And if you have lower loads, you may have lower impacts?

A. Yes. And but we got to be careful there. End of the light load issue, right, because you do have to look at that too and that becomes an issue with wind. If you had a lot of wind to your system, the wind tends to blow during low load periods so the issue there would be what also is happening with the wind from a lower load perspective type situation. But to your point, load does matter.

Q. So light load, I believe you ran into sensitivity in a light load scenario?

A. Yes, we did.

Q. And that was based on a 2017?

A. Yeah, it was the only one that was available.

Q. So that means you used RTEP for 2017?

A. Yeah, it was an RTEP.

Q. And in that case you assumed retirement of the PPA units in 2017?

A. Yeah.

Q. And are the results of that analysis

identified anywhere?

A. Well, the results didn't drive any new requirements. So all we did with that was we ran that as a sensitivity to look at whether or not the issue we added here we added in close to 7,000 megawatts I think of wind, somewhere in that neighborhood, to get the 880 megawatts of capacity.

Q. Right.

A. Required a lot of wind. There was a lot of wind in the queue. Name plate. And so when you do light load modeling, you model that wind at a much higher output, take it anywhere from 40 to 80 percent of it's name plate. So we did that analysis to see if there was any problems. We didn't see any problems so we didn't think too much about it any further.

Q. Okay. So your light load analysis you assumed all the PPA units retired, correct?

A. Yeah. We just made the same general set of assumptions and just ran in sensitivity just to test the wind assumptions under a light load condition just to see if we saw anything. But then again, sensitivity analysis, it didn't produce any additional need for reinforcements.

Q. And when you say no additional need, are you saying nothing beyond the 1.6 billion or just nothing at all?

A. No, nothing beyond 1.6 billion.

Q. Did it produce less than the 1.6 billion?

A. No, I don't believe so. I mean, we would put all the retirements in there and everything like that too.

Q. So you're saying so the exact same transmission upgrades were identified?

A. At that point we were looking to see if there were any new types of problems and we didn't see any new problems relative to what we saw in the peak load case.

Q. But are you certain that all of the same problems were identified in that light load case?

A. No. It was a light load case, not peak load, so it won't show the same types of problems because the generators are all modeled very differently, the load's all much lower, so you'll see a whole different set of results. We were just looking to see if there was a new set of problems that showed up that wouldn't be covered.

Q. So the light load case didn't identify the need for the same upgrades that you've identified in Sierra Club Exhibit 1?

A. It wouldn't -- we would not expect that; it's not a peak load case, it's a light load case.

Q. That's why it didn't; is that right?

A. Yes.

Q. Do you know what level in terms of costs of upgrade it did identify would be needed?

A. No. We just looked at the impacts. We just looked to see if there were any new impacts and that's where we stopped.

Q. And the light load case, when you say "light load," are you assuming a lower total load?

A. Yes.

Q. And that's just based on you're not using peak anymore?

A. Using 50 percent of peak.

Q. Okay. So leaving aside the light load case, if you were to use a different -- if you were to have lower peak demand forecast in your 2019 RTEP scenario, you would end up with lower transmission upgrade -- transmission impacts?

A. I think that's generally true. I won't say it's a hundred percent true but I think it's generally true.

Q. Okay.

A. Again, it depends because if the load drops in a way that creates flow patterns on your system that are different and those flow patterns result in reliability problems and that can happen. Depends on the flow in generation.

So it matters how you get that load, what resources you use to meet that load. I think your statement's true.

Q. And in your modeling you simply used, am I correct, the PJM forecast that was used in the 2014 RTEP?

A. That's correct.

Q. So you didn't modify that in any way?

A. No.

Q. Are you aware that PJM in January 2015 came out with a new load forecast?

A. Yes. Every year they do a load forecast.

Q. And to your knowledge is that -- is their new forecast lower than the --

A. I don't know that.

Q. You completed your modeling in August 2014, correct?

A. Yes.

Q. And you didn't make any changes or updates to it before you submitted your May 2015 testimony?

A. That's correct.

Q. And did you evaluate whether in submitting your May 2015 testimony you should run the model with a new load forecast?

A. No.

Q. And why not?

A. We didn't see any major transmission upgrade changes moving at that time so I think that was the kind of the deciding factor. There wasn't really any major changes in the network configuration so we felt it was, the results were going to be reasonably accurate.

Q. But in making that determination you didn't evaluate whether PJM had come up with any lower load forecasts; is that right?

A. That's correct.

Q. And did you evaluate before submitting your May 2015 testimony whether additional proposed units in the PJM queue had obtained ISAs?

A. No.

Q. Can we take a five-minute break.

(Discussion off the record.)

(Lunch recess taken from 12:00 noon to 1:00 p.m.)

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Friday Afternoon Session,

September 25, 2015.

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EXAMINATION (continued)

BY MR. FISK:

Q. Back on.

Okay, we can go ahead and mark this as Sierra Club 8.

(EXHIBIT WAS MARKED FOR IDENTIFICATION.)

Q. Mr. Bradish, you've been handed Sierra Club Exhibit 8 which is the company's response to ELPC, INT-2-029; is that correct?

A. Yes.

Q. And you were the sponsor on this response?

A. Yes.

Q. And did you draft this?

A. Under my direction, yes.

Q. The request is "Identify transmission upgrades currently planned or scheduled for the transmission facilities included in response to ELPC set 2-INT-28."

And then you have a response regarding a PJM recommended approval of a 450 MVar static var compensator.

A. Yes.

Q. So if you can also turn to page 7 of your -- of Sierra Club Exhibit 1, the Transmission Assessment.

A. Uh-huh.

Q. And I realize this is probably hard to do without -- on the record, but I'm trying to get a sense of generally is this project identified in Sierra Club Exhibit 8, would that be on the map that's on page 7?

A. Yes, it is.

Q. And where approximately would that be?

A. I believe it's here.

Q. Okay. And if you could just maybe describe that.

A. So that's the Jacksons Ferry 765 kV station. It's just a little bit -- it's in, I don't know what would be, what county that is. It's Virginia.

MR. MILLER: Use the letters perhaps.

Q. Just south of C?

A. Yeah, just south of letter C that's next to the F on the bottom of that diagram.

Q. And where it says "Jacksons Ferry"?

A. Where it says "Jacksons Ferry," correct.

Q. Okay. So your understanding is that there is a recommended approval before PJM for this project to move forward?

A. Yes.

Q. And do you believe that if that project were to move forward, would it affect whether upgrade C and/or F that you've identified would still be needed?

A. Yeah. It will have influence on the scope of the work required to remediate the issues in this area. So because C is several locations, it would affect this area primarily, so it's going to affect C but it's going to affect the C that's down here in Virginia, not necessarily the Cs that are up here.

Q. When you're saying "this area," you were drawing a circle around C and F?

A. The Jacksons Ferry area, yes, C and F, Jacksons Ferry, yes.

Q. So those upgrades potentially might not be needed or could be smaller?

A. Yeah, I think it will influence the scope of the work required in that area. We haven't done any type of analysis, this just came out by PJM, so, but it will influence the scope of the work required for that area.

Q. And that is a project that would be occurring in the AEP territory?

A. Yes. Yes, it is.

Q. And so AEP would be the one that would have to carry that out?

A. Yes.

Q. And do you know what the status of that is if PJM recently recommended approval?

A. Yeah, so my understanding is it's an official process PJM has to go through to make a recommendation, look to see if there's any feedback on that, and absent any feedback that changes their mind and if they're still doing any studies, then -- I'm not aware if they are or not doing any studies -- they'll eventually take to the board.

Once the board approves it, then it's good and we start taking action. So we still have to wait for the board approval. It just falls under the category of planned.

Q. I know we talked a little bit earlier about when proposed generating units might be included in PJM's RTEP. Do you know when proposed transmission projects might be included?

A. I believe once they're approved by the board they'll put them in.

Q. And to your knowledge if it's before that in the process, they wouldn't be included?

A. No.

Q. Do you know -- so the 2019 RTEP that you used, the determination of what transmission projects to include in that scenario would have been based on FERC approval as of kind of mid-2014; is that right?

A. Yeah. I don't recall when the model's finalized but it's finalized somewhere in the first half of '14.

Q. And did you do anything to determine whether any additional transmission projects had been approved by the PJM board between closure of the list that's included in the 2019 RTEP and when you submitted your testimony in May of 2015?

A. Yeah, so the RTEP analysis was done during the rest of '14 and there weren't any significant transmission developments that occurred during that RTEP that we thought would influence the results here. So that was part of the reason I gave earlier we didn't go forward and update the analysis.

Q. So that you're talking about there was no major developments during the 2019 RTEP process?

A. Yeah, so that would have run in 2014. It's looking forward five years.

Q. Right.

A. So it would have run in 2014 and so the results of that would have been towards the end of 2014 that you would have started seeing the results and knowing what's going on. And we didn't see anything that came out of that analysis that would, we thought would strongly influence the results here. This analysis is now the next series of RTEP, so this is the 2015 process.

Q. Right. So but your analysis in this proceeding was completed in August 2014, correct?

A. Yes.

Q. So the 2019 RTEP must have been completed before then, correct?

A. The case is put together and then they immediately start running the analysis and we start seeing what problems are there and what, based on those problems you got an idea of what the solutions are going to be, something like that.

So it's a -- then so it finishes up and then the question is do you rerun the analysis for the May '15 submittal, and we didn't see anything in that process that would lead us to believe we needed to redo the analysis at the time.

Q. Is whether the board of PJM has approved a transmission project public information?

A. Yeah. Once the board approves it, they announce it publicly.

Q. And did you verify whether the PJM board had approved any transmission projects after August 2014 that weren't included in the 2019 RTEP?

A. I don't know that we actually looked to the board approvals or not. I mean, we can look and see what the process is and what the problems are they're solving and kind of know what the scope of the solution is going to be and know whether or not there's going to be anything. Ultimately they get sent to the board for approval.

Q. You you didn't check the board approvals themselves, correct?

A. I personally didn't. I don't know if my staff did or not.
Q. You didn't ask them to do it.
A. I didn't.
Q. And so there's no transmission project approved after August 2014 that you added to the RTEP model that you used, correct?
A. That's correct.
Q. And I believe you said the 2015 RTEP process is now underway?
A. Yes.
Q. And do you have any involvement in that process?
A. My staff does certainly.
Q. And what sort of involvement?
A. Well, it's the same general process. PJM does the analysis, they share the results, my team then looks to develop exclusions to resolve the problems. And so we're going through that process now.
This is one of the first things that recently came out in the most recent Transmission Expansion Advisory Committee, TEAC, from PJM where they announced that they were going to move forward

and recommend this SVC.

Q. So AEP has received from PJM the 2015 RTEP that you're now going through; is that right?

A. Yeah. They provide -- publicly they're in a meeting when they present their results publicly. And that's where this got presented.

Q. Do they also give you, like, modeling files that you are then able to go through and figure out what solutions might need to be identified?

A. I think in this one there was probably, I don't know the details on this one because it's also part of a winter analysis they're doing too and I'm not sure, I assume there was some interaction to my staff saying here's the problem we're seeing, here's what we think the recommendation would be to fix that.

So I think the same type of general process and my team would send solutions to them and see if not -- PJM agreed with those solutions or not.

Q. But your staff would send solutions to PJM after PJM had provided modeling finals to your staff?

A. Yes. PJM does the analysis themselves and sends us the results. So they tell us hey, here's the problems we're seeing on your system and then we've got the cases that they use so we've got access to those. Which, by the way, we have to sign nondisclosure agreements to get access to them.

Q. Sure.

A. So we get all the cases and the results and then my team goes in and finds solutions to those problems.

Q. And when you say "cases," is that essentially the 2015 RTEP?

A. Yes, it's the RTEP case.

Q. So it's the 2015 version of the 2014 that you used in your analysis.

A. Yes, that's correct.

Q. So you have that at this point, the 2015.

A. Yes.

Q. And then you're able to use that to then run your system and determine what kinds of solutions might be needed.

A. That's right.

Q. And have you, has AEP proposed any solutions to PJM at this point?

A. I'm sure we helped with that one. I'm not aware of anything else of substance out there that's showing up at this point in time. But I haven't really discussed the 2015 RTEP process in detail with my team yet.

Q. Do you know what the schedule is on the 2015 RTEP process moving forward?

A. I don't. They've got some windows that they've got open and they're running through that process. So their evaluation is ongoing at this point in time. This is the first one decided they thought they were going to recommend something. But there's ongoing evaluations.

Q. Do you know if PJM is using a new load forecast in running it's 2015 RTEP as compared to what they use in the 2015?

A. Yes.

Q. That would be the new 2015 PJM load forecast?

A. That's right.

Q. I believe that came out in January of 2015?

A. Yeah, sometime earlier this year would have been when the cases all came together. So there is a process that PJM runs to collect all the inputs to develop their cases, so the RTEP model would have been finalized sometime the beginning of first quarter, first half of this year.

Q. And the modeling that you've done in this proceeding, have you discussed that with PJM at all?

A. No.

Q. Has anybody on your staff discussed that with PJM?

A. No.

Q. And you've never asked PJM to do any sort of analysis of what transmission impacts might occur if any of the PPA units were to retire; is that right?

A. That's correct.

Q. If you turn to page 4 of your testimony. There's a reference right up at the top of the page, lines 1 and 2, talking about the polar vortex. See that?

A. Yes.

Q. I guess it starts actually on the bottom of page 3. You have a reference to "...coal-fired PPA units can store a substantial amount of fuel on site, which helps maintain transmission grid reliability during adverse weather conditions...," you see that?

A. Yes.

Q. And the example you gave was the polar vortex in January 2014 and similar frigid temperatures that occurred in early 2015?

A. Uh-huh.

Q. Do you have any knowledge about the performance of the PPA units during the polar vortex of January 2014?

A. No, I'm not sure what they did.

Q. So you're not offering any testimony regarding that?

A. No.

Q. And when you say "the polar vortex," are you talking about specific dates in January? Or the whole month?

A. Well, I think there's probably certain dates in there that, wherein that term became popular that were very, very cold. I'm trying to recall off the top of my head what those were. I don't recall off the top of my head. I think they were in early January.

Q. And have you heard the frigid temperatures in early 2015 I think are called the Siberian express now?

A. Were they? I'm not sure I was aware of that.

Q. Fair enough. And do you have any knowledge about the PPA units' performance during the frigid temperatures that occurred in early 2015?

A. No, I don't.

Q. So you're not offering any testimony about that?

A. No.

Q. Have you evaluated the performance of coal-fired generating units in general during the polar vortex?

A. No, I have not.

Q. And same with regards to the January or the early 2015?

A. That's correct.

Q. And on lines 20 to 23 on page 4 you have a sentence that says While the transmission upgrades would mitigate identified NERC reliability standard violations, they would not cover all potential scenarios where the plants may be required to maintain system reliability.

A. Yes.

Q. What situations are you, or scenarios are you referring to that wouldn't be covered by the NERC reliability standards.

A. I think the concern there was we hadn't run the stability analysis yet. That's probably the primary driver of that. And the other fact I think it also went with the remainder of the answer in this section where we talk about nondispatchable type plants. When you get yourself into a critical situation, you need all the flexibility you can get in terms of dispatch plants.

So these plants have the ability to redispatch whereas other resources may not be so flexible in terms of their redispatch, especially renewable resources. So simply having the upgrades in place doesn't mean that at the end of the day you won't run into problems. Once you get situations on your grid work, you need to be able to redispatch around them, and if you don't have the resources to redispatch around them, you get yourself in trouble.

Q. And redispatching issues are not covered by the NERC reliability standards?

A. No, they're not. They won't cover all those situations. So it's just the fact of the matter in real life there's plants trip on and off, circuits trip on and off and so if -- you need the flexibility to deal with that. So just a statement about the flexibility of the plants and what they can bring to the table.

Q. And is it also your opinion that PJM reliability standards don't address or don't cover redispatching issues?

A. Not all.

Q. Are there some that they do cover?

A. Well, so I think the point being here is that you can still, even though you plan to meet our reliability standards you can still get yourself in a situation where you have problems. And the issue here is that you need generation that's flexible enough to move to address those problems.

Q. And by "flexible," what do you mean?

A. Able to move up and down on command.

Q. And quickly?

A. Yes.

Q. Do you believe that a natural gas combined cycle plant can move up and down?

A. Yes.

Q. And quickly?

A. Yes.

Q. So wouldn't natural gas combined cycle

units provide redispatch?
A. Absolutely.
Q. And would they address the redispatch issues just as well as the coal unit?
A. Yes.
Q. And how about a natural gas combustion turbine?
A. Absolutely.
Q. Just as well as coal?
A. Just as well.
Q. So your concern here is for things like wind and solar?
A. Yes. So I mean, as I said, as more renewable resources were added, so that is the issue. It's wind and solar issues that you want dispatchable plants available to be able to address those issues.
Q. And do you, in your opinion does demand response play any role in helping to address those kinds of issues?
A. I think demand does have a, can play some role there. If you're able to cut demand in a significant way to influence results, yeah, they can play a role there.
Q. And did you factor demand response into

your evaluation in any way?

A. Demand response is reflected in these models through their load forecast I believe. It's not modeled exclusively in RTEP that I'm aware of.

Q. So the only demand response that may have been considered was through the load forecast in the RTEP model?

A. Yeah, they would reduce the load forecast.

Q. Do you know if demand response played a role in helping to address the issues confronted during the polar vortex?

A. My understanding is PJM did use demand response to help. I just don't know how much.

Q. But it provided some help.

A. I believe. That's PJM's statement. I don't have personal knowledge of that. I believe that's what I read from PJM.

Q. And does energy efficiency help address the system stability issues that you're discussing on page 4, lines 21 to 23?

A. No, energy efficiency again is going to be reflected on the transmission system in terms of just to reduce load. So the load forecast would have been reduced by the amount of the energy efficiency that they would have projected to have been put in during that load forecast period.

So just all they do is, again, reduce the load forecast with energy efficiency.

Q. And you didn't assume any energy efficiency beyond what was that load forecast, correct?

A. That's correct.

Q. And with regards to the retirement, potential retirement of PPA units, did you evaluate whether any of those units could be converted to synchronous condensers?

A. I did not.

Q. Do you have any opinion as to whether synchronous condensers could address some of the reliability impacts?

A. Synchronous condensers could provide reactive power support so they can be helpful for that.

Q. And reactive power support would help address some of the transmission impacts you've identified in your analysis; is that correct?

A. That's correct. The synchronous condensers would be very similar to PSPC in terms of providing reactor support.

Q. Are you aware that, for example, I believe FirstEnergy is converting Eastlake to synchronous condensers?

A. I am.

Q. So a similar effort could be done say with Conesville?

A. I don't know. The generation guys have to have an opinion on that. There has to be evaluation of the plant and see if it's capable of being converted into a synchronous condenser.

Q. But if it were able to do that, that might be a solution to some of the Central Ohio issues you've identified?

A. Yeah, it could certainly provide benefits to Central Ohio.

Q. If you could go back to Sierra Club Exhibit 3.

A. Okay.

Q. So this is ELPC interrogatory 3-002, correct?

A. Yes.

Q. And the response on the second page on the first paragraph so it's scenarios 1 through 4, well strike that. So you discuss scenarios 1 through 4 and then you say in the second sentence scenario 5 including monitoring the neighboring systems. Do you see that?

A. Yes.

Q. And utilizing all credible contingencies in the PJM system. Do you see that?

A. Uh-huh.

Q. So when you say "monitoring the neighboring systems," what do you mean?

A. Basically when you run the analysis, you have to monitor when you simulate a contingency, which means a transmission outage, you have to monitor the impact on all the facilities. So you're looking at voltages and thermal loadings on the facility. So you're just monitoring those facilities to see if they're overloading or not. Or their voltages are not acceptable.

Q. And did you, through scenario 5 did you identify any transmission problems in those neighbor systems from the retirements that you assumed?

A. Yes, we did see problems.

Q. But you haven't identified those in your study, correct?

A. That's correct, we did not try to fix those problems.
Q. So we don't know what cost impacts of those, addressing those issues might be.
A. That's correct.
Q. Back to your responses, "utilizing all credible contingencies," what does that mean?
A. It's just in that case you're also looking at contingencies on your neighboring systems to see if they cause problems on your system. So just expanding the scope of contingencies and doing the comprehensive analysis that needs to get done.
Q. So in identifying the upgrades for the AEP zone you did evaluate whether contingencies in other zones would cause problems in the AEP zone?
A. Yes.
Q. And that factored into your identification what upgrades would be needed?
A. Yes.
Q. Now, on page 6 of your testimony, lines 11 through 13, you say -- there's a sentence there that starts with "The focus." Do you see that?
A. Yes.
Q. "The focus of my testimony will be to

provide an analysis of the transmission upgrades and the associated costs that will be incurred if the PPA units are retired." Do you see that?

A.   Yes.

Q.   Is it fairer to say "may be incurred"?

A.   Yes.

Q.   And is that because the analysis that you've done is not the full analysis that you would do to identify specifically what projects would be needed?

A.   That's correct.

Q.   And the analysis of the associated costs isn't the full study that you would do to determine those costs.

A.   That's correct.

Q.   And would it also be fairer to add to the end of that sentence "if the PPA units and the 111(d) units are retired"?

A.   Yes, so I guess it's, yeah, the 111(d) units that I modeled, yeah. I think that's a fair statement to say.

Q.   And those are the list of units we talked about this morning.

A.   Yes.

Q. And am I correct that the solutions that you've -- the transmission upgrades that you've identified, that analysis has not been optimized?

A. Yeah, that's fair.

Q. And what does that mean when you say it hasn't been optimized?

A. Well, one, it hasn't completed -- we haven't done all the stable analysis or other load stability analysis that we mentioned. You need to get eventually to the engineering so you have to find out, you have to go to site selection, you have to do the engineering analysis, you have to do short circuit studies. So that drives the size of the equipment you might need and station layouts, things like that. So there's just more detail engineering work that needs to get done before you get to the ultimate solutions.

Q. Okay. And when you say additional engineering work, does that include additional modeling work?

A. Well, yeah, to get the stability analysis done and all that stuff you have to use models for that, yes. Short circuit analysis as far as models.

Q. Ultimately is it PJM that would make the final determination what projects would be needed to address reliability impacts from retiring the PJM units?

A. I would characterize it more joint agreement between AEP and PJM. Because like I said, they give problems to us, we develop the solutions and then they test the solutions. So it's a partnership in that effort to come up. But ultimately they have to take it to the board and the board has to approve it before it becomes a project.

Q. So ultimately if there were a decision agreement, PJM would make the final decision?

A. Yes. In terms of whether we're going to move forward to their board, absolutely.

Q. And AEP can't move forward with a transmission project without PJM approval?

A. Actually there is a class of projects you can move forward with that are called supplemental that you can propose to move forward with. PJM will still test those and then make sure you're not doing any harm to the system. So as long as you're doing no harm, then they will say okay.

Q. But on supplemental projects that's not stuff you would use to address these issues, correct?

A. No, it is not.

Q. So in terms of these issues, any reliability upgrade would have to be approved by PJM.

A. Yeah, these issues are big enough they would be based on projects that PJM would have to be part of the solution on to move forward.

Q. So in your testimony on page 9, lines 3 through 10, you have the $1.6 billion figure and then there's a, I guess a division of that figure into 850 million that would be borne directly by customers in AEP zone?

A. Right.

Q. And then 750 million -- 50 percent of the remaining 750 million shared with other PJM members. You see that?

A. Yes.

Q. Do you understand how PJM does cost allocation for transmission upgrades?

A. To some level, yes.

Q. Okay. And am I correct that's set forth in schedule 12 of the tariff?

A. That's correct.

Q. And what's your general understanding of how that happens?

A. So there's things called regional facilities. Those are basically 345 kV double circuit and above that would be allocated, 50 percent of those would be allocated on a centralized basis across the PJM footprint with load ratio basis I believe it is.

The other 50 percent of those facilities would then be allocated to either the local zone or potentially multiple zones depending on this process that PJM runs to see who benefits from that. And that's where my detailed knowledge begins to run out. It's a very complicated process they run to figure out at the end of the day how that other piece is going to be allocated.

For the other nonregional facilities they get immediately assigned that same process where they basically use a hoop benefits basically from using that new reinforcement so there's a process that they run that uses something called DFAX, D-F-A-X, that looks, very complicated process that looks at beneficiaries on that -- to that reinforcement and decides who then pays what share. And that process is updated annually.

Q. Makes sense.

So the 345 kV and above you said double circuit?

A. Double circuit.

Q. And what does that mean?

A. Basically two lines running on the same -- two sets of conductors running on the same tower.

Q. Okay.

A. So there would be three phases on one side, three phases on the other side, double circuit line.

Q. And for those 50 percent of the cost goes to PJM as a whole based on load?

A. I think it's load ratio share. Those and above.

Q. And then the other 50 percent you'd have to do the DFAX method to determine?

A. Yeah.

Q. And is DFAX something that AEP is able to do on its own or PJM has to do that?

A. PJM has to do that.

Q. So you're not able to replicate what they do?

A. No.

Q. But the DFAX method would assign it to the zone or zones a benefit from the project.

A. That's correct.

Q. So if a cost is assigned to a zone based on benefit, does everybody in that zone pay for it?

A. Yes.

Q. So for AEP the zone covers seven states, parts of seven states?

A. Yes.

Q. So any costs that would be allocated to the AEP zone would not just be paid by Ohio customers, correct?

A. That's correct.

Q. Do you know, is it just allocated evenly across the zone?

A. I think it falls out, again, load ratio share.

Q. Okay.

A. So AEP would pick up its load ratio share, the larger AEP, and then within AEP there's an allocation of transmission costs based on our transmission agreement we have in place among the member companies.

Q. Okay.

A. That further allocates the cost among the

AEP companies.

Q. And do you know what portion of the allocation AEP-Ohio would get?

A. I don't know that number off the top of my head. I think Witness Allen has that number.

Q. Do you know a general percent?

A. I don't know. I don't know, it's 15-20 percent, something like that. Somewhere in that range.

Q. And so then you said for other projects, which I assume would be 345 kV single circuit.

A. Right.

Q. Or anything below 345 kV?

A. They just get the DFAX method.

Q. Which is who benefits a hundred percent.

A. Yeah.

Q. Am I correct that's for products over 5 million? Right?

A. That's correct.

Q. So if it's over 5 million, it goes to the zone where it's allocated?

A. That's correct.

Q. And that's for, well, if you could turn to page 8 of the Transmission Assessment.

A. Okay.

Q. We discussed earlier I think some of these projects are transmission lines, some are substations.

A. Yes.

Q. And some are MVar SVCs?

A. Yes.

Q. Does that cost allocation method that we were just discussing apply to substations?

A. Yes.

Q. So if a substation is 345 or above.

A. Depends where the substation is connecting in. So in the two substations we have here, the 345, the top one, A and B, the assumption there that would be bringing a double circuit line into that substation. So on the substation that's located on the double circuit line, it would be treated as the regional facility and so some of that cost would be allocated.

Q. So projects A and B would both be 50/50?

A. Yeah, they'd have a mix of both. So they're going to have, A and B have a piece of that would be simply just dedicated to the AEP zone would be a logical facility, and then there's a part of that project like I talked about when I say the station costs include the transmission line work coming into it.

So part of that station cost would be that transmission line coming into, the double circuit work so that work would get regionally allocated. So the 50 million is going to be broken up into the two buckets.

Q. And then the 138 kV upgrade on project C, those would all be a hundred percent DFAX?

A. Yes.

Q. And same with project D?

A. Yes.

Q. How about project E, is that allocated?

A. At that point we think it's again going to be probably a 345 kV station and it's probably going to have double circuit coming into it, so for this analysis we assumed it would be regional so it would be 50/50.

Q. Project F would be 50/50, correct?

A. Yes.

Q. Project G, would that be 50/50?

A. Yeah. Again, the line is 765, the Adkins station is 765 so you're at 50/50.

Q. And project H?

A. 50/50 because of the 765.

Q. Project I?

A. I think that would all be local.

Q. And project J is 50/50?

A. Yes.

Q. And for the DFAX portions which for some is 50 percent, some of it's a hundred percent, do you know for any of these upgrades exactly who benefits?

A. No.

Q. So it's possible that for any of these upgrades people in other PJM zones could receive some benefits?

A. It is possible. It doesn't happen very often but it's possible.

Q. And if that were true, then some of the costs under the DFAX methods go to those zones.

A. That's correct.

Q. And if you look at the map on page 7, for example, if you look at let's say project J, that appears to me at least to be kind of right on the border of another zone; is that right?

A. Yes. So J is the Stuart so, yeah, that's either the --

Q. Looks like EKPC.
A. Yeah, there's EKPC then there's Duke is in that general area also.
Q. Does the fact that project J is kind of right on the border suggest that maybe some of the benefits may go to another zone?
A. Given this location there's a possibility that some of those costs would be assigned to other zones, absolutely.
Q. And would that be the same for H?
A. It depends on the -- what matters is the underlying prevailing power flows. And I don't know but it's on the border and I don't -- that one I'm not as familiar with that general area so I'm not sure. I can't say.
Q. Any of the other projects on here that based on their location it appears some of the benefits might go to another zone besides AEP?
A. The only other one I might add would be F.
Q. The one down near Jacksons Ferry?
A. Yeah. It's mostly in our area but depending on how the response factors work out.
Q. And the final cost allocation determination, those would be made by PJM, correct?

A. Yes.

MR. FISK: If we could go off.

(Off the record.)

Q. Back on.

When you ran your modeling runs, did you run the 2019 RTEP system without any changes first to determine if there were issues or transmission problems identified?

A. Help me understand your question, please.

Q. Well, I guess I'm trying to figure out you've said that when you make various changes to the RTEP, you come up with this list of transmission upgrades that are needed because you've identified issues, right?

A. Uh-huh.

Q. And I guess I'm trying to figure out compared to what baseline.

A. So we, I guess then we did not make any changes to the initial RTEP model that we started with other than the ones we talked about. So we didn't do any analysis on the initial RTEP model other than the analysis that we've talked about.

Q. So does the RTEP model that you get from PJM without any changes, if you just run it, are there no problems identified?

A. I don't know. I've never asked that question.

Q. So, like, looking at your list of upgrades, the upgrades that you identify in your Transmission Assessment, those are upgrades to identify problems or transmission reliability issues.

A. Right. Right.

Q. From when you ran the model with your changes, correct?

A. Uh-huh.

Q. So are you able to tell me sitting here today whether if you ran the 2019 RTEP without any of those changes, do you know whether the transmission reliability issues you've identified would have already appeared?

A. Yeah, I guess they would not have appeared. The reason I can say is they did not show up in the RTEP analysis that PJM ran.

Q. So when PJM itself ran the 2019 RTEP.

A. The problems that we saw did not show up in their analysis.

Q. And you've seen their analysis to know that?

A. Yeah, my team has seen that and we have proposed solutions to those. That was all done last year.

Q. Okay. So whatever problems were identified in that RTEP were different than ones you're now identifying.

A. That's correct.

Q. AEP has proposed solutions to those?

A. Yeah, I'm trying to remember if there was anything of significance on our system. I don't recall any major issues on our system, to get to your question of proposed solutions. I don't remember any major problems, so if there are minor problems that show up, we would have proposed solutions in that process.

Q. And do you know, are the solutions that you proposed, are those publicly available?

A. Yes.

Q. And did the solution -- so the solutions you proposed would still be working their way through the PJM approval process; is that right?

A. Probably would have been approved at the end of last year.

Q. Did you include those solutions in the

RTEP modeling that you ran for this case?

A. No, we didn't make any changes to the case. So again, the reason, one of the reasons why we didn't redo the analysis is because we didn't see any problems on the grid that were going to be related to these problems. So those problems just didn't exist.

Q. And we talked earlier about the approximately 15,000 megawatts of unit that you turned on. Did you -- as of what date did you turn those on in the model?

A. I think it was set for 2019.

Q. So those would have turned on June 1, 2019?

A. Yes, I believe 2019.

(EXHIBIT WAS MARKED FOR IDENTIFICATION.)

Q. So I have handed you, Mr. Bradish, Sierra Club Exhibit 9, which is the response to Sierra Club interrogatory 2-072; is that correct?

A. Yes, it is.

Q. And you are identified as the preparer for this response?

A. Yep.

Q. And did you draft this response?

A. At my direction, yes.

Q. And so subsection a. of your response lists the same projects or upgrades that we've discussed previously; is that right?

A. Yes.

Q. If you turn over to subsection C, which I guess the request had said "Identify what portion of the $1.6 billion would be paid by Ohio ratepayers." See that?

A. Yes.

Q. And then there's a discussion about the allocation in your response; is that right?

A. Uh-huh.

Q. The last sentence says "DFAX and Market Efficiency analyses may result in a different allocation." See that?

A. Yes.

Q. We discussed the DFAX earlier. Correct?

A. Yes, we did.

Q. What is the market efficiency analyses?

A. Now you're digging to another level. So they do the DFAX analysis and that gives them the response factors, and then my understanding is, and this is just general understanding, is that they then run market efficiency which is basically looking at how that facility would be used throughout the year by those loads that had been identified as beneficiaries. And they combine that, they look at that result to get to their ultimate decision on who gets allocated. And that's as far as I can go in trying to explain this.

But it is a multi-step process. DFAX identifies the participants and market efficiency type analysis which is a production cost modeling that models 8760, all the powers in there So they can get an estimate of what the flow on that facility would be as a result of these entities. And they use that somehow based on figure 12 how to figure out what the final result is going to be. So it is a multi-step process.

Q. And that market efficiency portion of the analysis, that only applies to the portions of cost that were under the DFAX?

A. Yes.

Q. And the market efficiency analysis is not something that AEP itself could carry out; is that right?

A. We can do market efficiency but we

wouldn't do it for this situation.

Q. Okay, fair enough.

And you don't know what the results for the market efficiency analysis would be for any of the upgrades you've identified, correct?

A. I do not.

MR. FISK: I believe I have no further questions. Right on time.

MR. MILLER: So Shannon has concluded, those on the phone. What does that do to your timing, and I guess we'll figure out what order you want to go in.

MS. PETRUCCI: This is Gretchen. I'm kind of in the same timeframe I was before and it doesn't matter if I go next or not.

MR. MILLER: Madeline, you said you had an hour?

MS. FLEISHER: Yeah, I think I'm under an hour now and I don't have any particular time constraints so I'm happy to go next or defer to anyone else, whatever works.

MR. MILLER: Let's do them in decreasing order, so I'm hoping your less-than-an-hour is the most, so why don't we do you next, if you don't mind.

MS. FLEISHER: Sure, no problem.

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EXAMINATION

BY MS. FLEISHER:

Q. Mr. Bradish, my name's Madeline Fleisher, I represent the Environmental Law and Policy Center, and just if at any point you can't hear me, I'm going to try to be as clear as I can but just speak up. Or if anything I'm saying just isn't clear because of the actual content, I'm happy to clarify.

A. Okay.

Q. So you said that you utilized the 2014 PJM load forecast for your analysis, correct?

A. That's correct.

Q. Okay. And I just want to get a sense of your familiarity with the PJM load forecasting process. Is that something that you have any familiarity with?

A. No, I do not.

Q. Okay. Do you generally review PJM load forecasts at all?

A. I don't.

Q. Would people under your supervision review them?

A. So there's two components to that: There's a Load Forecasting group within AEP that prepares the load forecasts for AEP, so they've got the primary responsibility, and then the folks underneath my team look at the distribution of that load on the buses and the what we call the power factor of that load.

Q. And is that load forecasting analysis, is that for purposes of providing for PJM for their load forecasting process?

A. That's correct.

Q. And are you familiar with AEP's preparation of fundamentals forecast internal to AEP?

A. I am not.

Q. And when you -- you mentioned that you, in trying to project retirements associated with 111(d) you looked at option 1 in the IPM modeling for the proposed Clean Power Plan; is that right?

A. That's correct.

Q. And you didn't look at that modeling involved, someone else looked at that and gave you a list of associated plant retirements; is that correct?

A. Yeah. That's correct.

Q. And do you know whether that modeling projected any energy efficiency for load reductions occurring in the AEP zone?

A. No, I don't know what EPA did from an energy efficiency modeling respect.

Q. And do you know anything about what load forecast is associated with that option 1?

A. I do not.

Q. Are you aware that energy efficiency is one tool for lowering carbon emissions to comply with the Clean Power Plan?

A. I was aware in the proposed rule one of the four, I guess, buckets that they had was an energy efficiency bucket. I think that's changed in the final rule they've -- my understanding is that's changed somehow. They've dropped it as one of the four and they're down to and I don't readily know what that means other than that I do know, like I had indicated earlier, energy efficiency is used by PJM to offset load. So if there are energy efficiency projections within the PJM process, PJM will use that to reduce the load in the case.

Q. And do you know how PJM forecasts energy efficiency?

A. I don't know if they actually forecast it or if they receive that from market participants.

Q. And are you aware that Ohio has statutory energy efficiency requirements?

A. Generally familiar but I'm not -- I don't know any of the details.

Q. And do you know whether the PJM load forecasting process takes account of the statutory energy efficiency requirements?

A. I don't know.

Q. And do you know whether the PJM load forecast takes account of any load reductions that might occur in connection with compliance of the Clean Power Plan?

A. I'm not sure what you mean by that question.

Q. So you said you understood that at least under the proposal, which was what was around for when PJM was doing its 2014 load forecast you understood that that had energy efficiency as a building block, correct?

A. That's correct.

Q. And do you know whether the 2014 PJM load forecast looked at how that energy efficiency building block might affect load within PJM?

A. I do not know if PJM took that into account.

Q. And going back to the option 1 modeling that you derived your list of retirements from for 111(d), do you know whether that option 1 forecasts any new generation in Ohio?

A. I don't know the location of the new generation other than I do understand that the EPA, when they retired generating units, they made assumptions that those units would be replaced somehow with new generating units. But I'm not familiar with the location of where they thought those new generating units would be located.

Q. Okay. So you didn't incorporate any such projections of new generation in your --

A. I did not use any projections from EPA on new generations. I used the PJM queue for that information.

Q. But you did use the EPA retirements.

A. I did.

Q. And if you can pull out Exhibit 5, the Sierra Club 5 interrogatory 119.

A. Okay.

Q. From looking at part a. I just want to clarify a couple things. I'll try not to repeat anything that Mr. Fisk went over with you.

So what I'm trying to figure out is how what you did compares to what PJM would do if any of these units announced retirements. So for generators with capacity of less than 5 megawatts if these PPA units announced retirements and PJM was doing its own reliability analysis, would PJM model generation from generators less than 5 megawatts?

A. My general understanding is that PJM would use all FSA units in their analysis.

Q. Okay. And when you said, when the response says "generators with capacity less than 5 megawatts totaling 200 megawatts were not modeled," is that referring to only FSA units less than 5 megawatts or does that include existing units less than 5 megawatts.

A. That was FSA units.

Q. And does the PJM interconnection queue include behind-the-meter generation? And I'm referring there to distributed solar but also combined heat and power cogeneration projects.

A. I think by definition if it's in the PJM queue, it's no longer behind the meter, it's visible. So I think by definition I don't believe so. But I'm not completely hundred percent on that.

Q. And would you say that generators with capacity over 5 megawatts could have an impact on your analysis?

A. Generators over 5 megawatts could have an impact on my analysis, yes.

Q. Okay. Do you know whether there are any combined heat and power projects proposed within AEP service territory?

A. I'm not aware. Doesn't mean there aren't, I'm just not aware.

Q. And do you know whether behind-the-meter generation is accounted for in PJM's load forecasting?

A. That would -- so I don't do the load forecasting so I can only speculate on that. My view would be it would be yes, but I'm speculating at this point.

Q. Appreciate you qualifying that.

And so for the next sentence regarding nuclear uprates, for nuclear uprates that are FSA units, would PJM, in doing a reliability analysis,

include all of those?
    A.   Yeah, if they were FSA units, I believe they would. If their in-service states meet the requirement, they would include them.
    Q.   And so for the ones that you excluded do you know whether that would include an uprate in the Peach Bottom area?
    A.   I don't recall which ones of the uprates that we did not turn on.
    Q.   And one more just to see if it triggers memory. Do you recall any in the LaSalle area that you would have excluded?
    A.   Again, I don't recall what uprates were in there.
    Q.   And then with respect to the generation stalled more than three years and requiring transmission uprates of more than 25 million, would PJM include that generation in a reliability analysis assuming it was at that FSA stage?
    A.   Yes, they would include it.
    Q.   And why did you use the three-year and $25 million criteria in excluding those units?
    A.   Well, we needed to -- we didn't need all the FSA megawatts so we needed to reduce that

somehow. And we felt that a good way to reduce that would be to reduce it by the plants that had -- were -- I guess have a higher probability of not moving forward. So that was our assessment.

If they hadn't moved in the last three years and they have a higher transmission cost than others, meaning $25 million, then our assessment was there's a higher probability that those would not move forward and so that's why we took them and did not include them.

Q. Okay, and so for those where you excluded those you would have modeled increased dispatch from other FSA units; is that correct?

A. That's correct.

Q. And why would you do that tradeoff? Would it be the closest other FSA unit or is there some -- it's just the model does it?

A. Well, I just I think we scale them all I guess proportionately until we get to the megawatts we needed.

Q. Skipping around a little bit.

For the transmission costs that the cost estimates for the projects that are in Sierra Club Exhibit 1, so you indicated those were based on AEP's experience with past projects, correct?

A. Yes.

Q. And for item G, the Adkins, I'm on page 8 here of the exhibit, the Adkins, are there any particular projects that you had in mind as indicative of the cost for this one?

A. Well, we've built several projects that are similar so we're in the process right now of building a new 765 kV line through Indiana that runs from Greentown over to Reynolds. We just built a 765/345 kV station we call the cell in northern, northwest part of Columbus outerbelt area.

Not too long ago we built a 765/345 kV station. Actually we're building one now I guess. Not "I guess," we are. We're building one now at Sorenson in Indiana. And we are doing a 765 kV line work to bring the line to, Dumont Marysville line into the Swanson station. So we've got some current projects that are fairly similar.

Q. And so do you have per-mile cost estimates for those that you then translated to this project?

A. Yes. So we're using that, we're using -- we didn't use a specific project cost, we're just using the collective experience we have. But that's what we do, you apply basically a per-mile type number to this.

Q. And do you -- I think you said for the 138 kV line it was about a million dollars a mile. Do you recall for 345 or 765 what you used?

A. The 1 million per mile for 138 was for reconductoring. I'm trying to think for the 765 kV, I believe it's 4 million a mile for new build. And for 345 kV, I believe it's 3 million a mile for new builds.

Q. And so for the 2015 RTEP case am I -- did I catch it right that you said you have that as of first quarter or first half of 2015 from PJM?

A. Yeah, that case was finished earlier this year, that's correct.

Q. Would you have had it at the time you were preparing your May 2015 testimony?

A. I'm not sure if it would have come out. It's right around that timeframe. It would have come out before May but I don't know how far enough in advance it would have come out.

Q. And I think you said you're now going through the process for the 2015 RTEP of proposing new transmission projects; is that right?

A. That's correct.
Q. And you said you have a sort of, to the best of your recollection some not-that-significant projects, if I'm characterizing that correctly.
A. That's correct.
Q. Is that -- is there sort of a normal baseline level or is every year different in terms of the amount or significance of transmission projects you'd be proposing?
A. Yeah, every year's different.
Q. Is there always something that you're having to do?
A. It does seem to be that way for the last two years there's always something to do. Especially with the MATS. The MATS generation retirement drove a lot. So we're doing a lot on our system now.
Q. And are there ever transmission projects that are driven by just the age of the system or natural wear and tear rather than retirement?
A. Yes.
Q. Are those relatively common? I'm just looking for your sense, overall sense.
A. Yeah, I mean, there's aging infrastructure so I think it's pretty common finding ourselves to

address aging infrastructure on a fairly regular basis.

Q. And you may have discussed this with Mr. Fisk, I'm not sure I caught it. Do you have any sense, I know there's a lot of facilities, transmission facilities involved in this analysis, but are there any that are sort of towards the end of their useful life, so to speak?

A. Not that I'm aware of.

Q. And I was wondering whether you have any familiarity with the Path transmission projects that was proposed a while back in PJM.

A. Yes, I'm aware of it.

Q. And is it your understanding that that project ended up being canceled?

A. Yes, it is.

Q. And was part of the reason for that cancellation that load growth was not as great as had originally been projected?

A. I believe that's part of the reason, yes.

Q. Are you, have you had experience with any other transmission projects that ended up not being needed because loads didn't reach the peaks forecasted?

A. Not that I can recall off the top of my head. Sorry, I just can't recall any right now if there was or not.

Q. Okay, that's fine.

And do you deal with transmission projects in the area of the Utica and Marcellus shale?

A. So when you're saying "in the area of Utica and Marcellus shale," what geographic? Can you bring that a little bit closer to me?

Q. Sure. I'm referring to generally Northeastern Ohio, Eastern Ohio.

A. Yes.

Q. And is AEP planning to do any, by "planning" I mean contemplating any transmission projects in that area?

A. Yes, we are.

Q. And can you describe those?

A. Most of that is 138 kV type facilities that we're using to connect the new gas processing plants and I guess the gas fracking plants, or whatever they are, facilities. So most of it's 138, however, we are building a new 345 kV station we call Holloway that's over near FirstEnergy's, I believe it's Berger plant. So there is a facility over there that we're building also.

Q. And do you know whether those transmission projects would have been included in 2019 RTEP case that you used in your analysis?

A. Yes, they would have.

Q. And does AEP ever do transmission projects for reasons other than to resolve reliability violations?

A. So we do address aging infrastructure that we talked about earlier. And we also do things like SCADA, supervisory control and data acquisition. So we are upgrading and adding new SCADA facilities. We do telecom which are part of our transmission infrastructure. We do customer connections that we just talked about for shale gas, those types of things. So, yeah, there's a set of other projects that we do that are not driven purely by reliability criteria.

Q. And when you upgrade transmission, does that -- putting -- hold on, let me try to phrase this in a comprehensible way.

When you upgrade existing transmission, does that improve the performance of the transmission facilities?

A. You know, if you just replace it in kind, it doesn't necessarily improve the overall reliability performance of the system per se. It's merely maybe providing overall reliability performance of that particular facility. But in general when you're enhancing the grid, you are improving the overall reliability of the grid at the same time.

Q. And say you were to do some of the upgrade projects listed in your analysis, would that generally lower the impedence of the lines in question?

A. I think that's a fair statement. Generally if you're adding new lines in, you are typically lowering the overall impedence of the system in general.

Q. Sure. And sorry, did you --

A. I'm holding out, there may be the chance you could do something where there might be a local increase in the impedence but maybe overall network might benefit from that too. But in general.

Q. And does lowering impedence reduce line losses on the system?

A. It can. It will again, ultimately what will drive line losses is not just the impedence but also the ultimate flow that occurs. So it's something you have to look at together because if you change the power flows enough, you may not get the loss impacts you were looking for.

Q. And when you did your analysis, did you look at sort of where the new generation would come from for AEP customers?

A. We did not assign any generation to AEP customers, so it is, basically it is the PJM market that will supply the generation.

Q. And did you look at all at whether the changed dispatch would affect locational marginal prices for within the AEP zone?

A. No, we did not.

Q. Would it be possible to do that?

A. It is possible to run a market efficiency analysis that would assess congestion. I'm not a price forecaster so I would not want to pretend that I'm going to forecast LMPs. But we could do market efficiency analysis that would ultimately look at any changes in congestion as a result. That way you only have to worry about differences in prices and not the absolute value of the price.

Q. Right. And moving to the various scenarios you ran, is there a reason you didn't look at retirements of the OVEC units?

A. I was not asked to.

Q. And who would have told you which units to consider?

A. The folks putting together the PPA.

Q. Anyone in particular?

A. I don't know who that would have come from. Somewhere between Pablo Vegas, I guess Chuck Zebula, Rich Muczinski, the three of them. Pablo Vegas being the Ohio representative, Chuck the AEP Generation Resources representative, and Rich Muczinski being Regulatory. And then I put in our legal counsel. So somewhere among that group they would have decided we need to do this.

Q. If you give me one minute, I may be done.

Okay, two quick questions.

So looking back on your general experience, have you -- I know you said you haven't been involved in negotiating any RMRs. Have you dealt with at all transmission upgrades in situations where there is an RMR in place?

A. I don't think so.

Q. And then for the Clean Power Plan I think you said your understanding of the compliance date for the proposal was the initial compliance deadline was 2020; is that right?

A. The proposal was 2020, that's correct.

Q. And do you have any knowledge of whether there's the ability to average 2020 with subsequent years in determining compliance?

A. Oh, I'm not that familiar with the Clean Power Plan requirements. I defer those to Witness McManus.

Q. Okay. Lucky you.

All right, that should be all I have. Thank you very much.

A. You're welcome.

MS. FLEISHER: Well under an hour.

MR. MILLER: 25 minutes.

Gretchen, I think you're up.

MS. PETRUCCI: Okay, thank you very much.

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EXAMINATION

BY MS. PETRUCCI:

Q. Let's stick with the Clean Power Plan retirements that you indicated were included in your impact study. How many retirements were specifically associated with the Clean Power Plan?

A. I don't recall.

Q. Do you know how many plants were to be retired in the impact study overall?

A. Oh, the ones that we actually just used in our analysis?

Q. Yes.

A. Yeah, we have a list of those plants.

Q. Is that included in Deposition Exhibit 1?

A. Find it here in a minute.

The list of plants is, sorry, looking.

So Exhibit 4, Sierra Club Exhibit 4 in today's deposition had the list of plants.

Q. Okay, thank you.

MR. MILLER: And for clarity, Gretchen, you're talking about the list of plants that were included in the model, correct?

MS. PETRUCCI: In his impact study.

A. Okay.

Q. I'm trying not to jump around but I think I'll probably do that.

There was an indication, and I'm sorry, I can't point us to the right spot where it was, but it stated that the capacity added into the impact study was roughly the amount of capacity retired.

A. Yes.

Q. Can you tell me what capacity added is capacity in Ohio?

MR. MILLER: Can you ask the question again?

Q. The capacity that was added in the impact study, what was the capacity that was -- that's located in Ohio that was added to the impact study?

A. Okay, so there were, if I recall there were two plants, two major plants -- there were gas plants, I'm sorry. One is an Amp Ohio plant that's located over off of our Sporn Waterford transmission line, another one was the upgrade to the plant at Flatlick, and then there was a plant that was over on the Pennsylvania-Ohio border and I can't remember the name of that one that was added, and those are all gas plants.

Then there were several wind plants that were also added, and I don't know the locations for those. So those were the ones in Ohio that were fully added to the case. Or turned on, I should say, in the case.

Q. Then can you tell me again the second one that you said it was an upgrade to and I had trouble understanding what you said.

A. There's a plant at Flatlick that is looking to upgrade from I think a simple cycle to combined cycle I think is what they're trying to do. So that one was added to our -- turned on in our case.

Q. Then I believe you earlier stated that one of the assumptions in the impact study was that all the PPA units would retire at the same time; is that correct?

A. That's correct.

Q. And can you tell me why that assumption was made?

A. Well, essentially we only ran one year, right? We ran 2019 to assess the impacts. So the assumption was that in 2019 they would all be retired.

Q. If there was a staggering retirement of all of the PPA units, are you saying that you -- I guess are you saying that you couldn't do a staggering of the PPA unit retirement dates? Because you relied upon the 2019 RTEP model?

MR. MILLER: Can you rephrase that? I think you're sort of stating his testimony a little bit.

Q. My question is is the reason that the PPA units were not staggered for retirement purposes because you used the 2019 RTEP model?

A. No. The reason they're not staggered is I was asked to assess the impact of the retirement of all the units. So I took the RTEP model for 2019 and retired all the units.

Q. Do you agree that there's more than -- that they could have been staggered for purposes of assessing what the impact of the units might be at retirement?

A. Yes. We can do a multi-year analysis to look at staggering.

Q. And you're not offering an opinion as to whether any or all of the PPA units should retire, correct?

A. That's correct.

Q. And you are also not offering an opinion as to whether any or all of PPA units will retire, correct?

A. That's correct.

Q. Looking at Deposition Exhibit 1, the date on it says September 4, 2015. Is that date accurate?
A. I'm not sure what you mean by "accurate."
Q. Is this PowerPoint that was marked as Deposition Exhibit 1 actually the output from your impact study or is this a summary of the output?
A. This is a summary of the output.
Q. And this summary was put together after you filed your testimony.
A. Yes, it was.
Q. If we can continue to look at Deposition Exhibit 1 and if you could pull out your testimony and turn to page 8.
A. Okay.
Q. And specifically looking at lines 18 to 19, there's a reference to the surrounding states. Is that, those surrounding states the ones that are listed in Deposition Exhibit 1, page 4?
A. No. I would direct you to page 7 of that same exhibit, Deposition Exhibit 1.
Q. And then the states that are depicted on the map are the ones that you were referring to?
A. The ones with the letters on them, yes.
Q. And then continuing with that same page 8

where you began to list the upgrades that were found from your impact study, that's the list that's included in Deposition Exhibit 1, page 8, correct?

A. Yeah, starting on line 21 on page 8 of my testimony, yes, the upgrades shown in exhibit, Deposition Exhibit 1, page 8, are the same.

Q. And then looking at page 9 of your testimony where you discuss a little bit about the allocation of costs, on what basis did you determine that $850 million of the upgrades would be borne directly by customers in the AEP zone?

MR. MILLER: Can you direct him to a line?

Q. Specifically lines 6 to 8.

A. So what I'm talking about there is the cost allocation method used by PJM in their processes. So we applied that cost allocation method to these upgrades to figure out how that cost would break out.

Q. And then for continuing on lines 8 through 10 on page 9, the allocation of the $750 million is also based on how PJM has allocated in the past, correct?

A. That's correct. That's their current cost allocation methodology.

Q. And if I recall from questioning earlier, you do not know what amount of money for these upgrade costs would be allocated specifically to AEP-Ohio and its customers, correct?

MR. MILLER: Let me kind of object. Are you -- is that a direct quote or are you just asking him a question?

MS. PETRUCCI: I'm following up on what I believe he indicated earlier today in the deposition, that he does not know what the allocation would be on his estimated transmission costs for AEP-Ohio.

A. So the allocation we gave you is an approximate allocation that I think is reasonable but I do not know what the ultimate allocation PJM will do because we did not run the DFAX analysis nor the production cost analysis to precisely do the allocation.

Q. And in order to understand the percentage that would be allocated to Ohio, AEP-Ohio, those items would have to be run; is what that you're saying?

A. When you say "items," what do you mean by that?

Q. You just listed I think two things that you didn't do.

A. Oh.

Q. That you indicated, I thought, needed to be done in order to determine how much would be allocated to AEP-Ohio in cost for these transmission upgrades.

THE WITNESS: Can you read back what my answer was, please?

(Record read.)

A. Yeah, so we have not done the DFAX analysis and we haven't done the production cost analysis that is required to find -- to determine ultimately what the allocation would be.

Q. Okay, thank you.

A. Sure.

Q. With regard to the RMR designation, earlier you indicated that you did not know if generators had declined that RMR designation. If AEP had declined an RMR designation, is that something that you would know due to your position with the company?

A. I believe so. I think it would be fair for me to probably know that.

Q. Just give me a moment here.

A. Sure.

Q. Let's turn to page 4 of your testimony, lines 16 and 17. In this area you're talking about Central Ohio and the retirement of the Conesville unit.

A. Okay.

Q. Is Central Ohio's load served directly by the Conesville unit?

A. Yes.

Q. Is it served only by the Conesville unit?

A. No. Other units have to supply power.

Q. I'm not sure I understood the second part of your answer there. Can you explain further?

A. So you asked if, well, can we read back her question?

Q. My question was is the Central Ohio load served only by the Conesville unit.

A. And the answer to that is no.

Q. And then if we could look at line 13 where you've indicated "Central Ohio is particularly sensitive to this imbalance," can you be more specific as to what imbalance you're discussing? Was it power flows or reactive power deficiencies or something else?

A.   Sure. So the situation would be a supply/demand imbalance, meaning if the Conesville unit is retired, there will be an even larger imbalance between the local demand and the local supply, meaning there basically wouldn't be any more local supplies. Because most of the generation is located away from Central Ohio.

So the concern would be that now you have this big distance between the major load center and the resources that are supplying it, which opens that load center up to increased reliability problems.

Q.   When plants retire, is there a process by which notification has to be given before the retirement can take place?

A.   My understanding it's a 90-day notification to PJM.

Q.   And then does PJM notify others?

A.   I'm not sure who you mean by "others." There's a defined process that PJM runs for generation deactivations, and I don't know the, all the particulars about it, but there's a 90-day notice provision and PJM will immediately go into action to do certain things to address the requests by the generator to retire.

One of those things it will do is it will look at reliability impacts of that generator retiring.

Q. And if we can turn to page 6 of your testimony, lines 19 to 20. You use the words "equivalent generation." Can you explain to me what you meant by that?

A. Basically a megawatt-per-megawatt exchange. We're looking to balance out the generation that's retired with new generation being added.

Q. And that relates to the conversation we had I think very early on about the capacity being added in was roughly equivalent to the capacity retired?

A. Yes.

Q. The 2019 RTEP case that you started your impact study with, that included already-planned transmission upgrades as of 2019; is that correct?

A. Yeah, all transmission upgrades that were planned to go in service by 2019 should be in the case.

Q. Now, does that mean, therefore, that there could be planned transmission upgrades beyond that would -- let me start again.

Does that mean that there are possibly planned transmission upgrades that would not go into affect until after 2019 that would have not been incorporated into your impact study?

A. Not that I'm aware of.

MR. MILLER: Let's go off for a minute.

(Off the record.)

MR. MILLER: Why don't we go back on the record, and Gretchen, you can continue.

Q. Thank you. If we can turn to page 10 of your testimony, lines 9 through 12.

A. Okay.

Q. You refer to additional at-risk generations. What are you referring to there?

A. The concern here is that there may be other generators. In particular there's some FirstEnergy generators that are units at risk. And so we go back to the same concern I have, that we had with the MATS is there's other generation that's going to retire at the same time. It just heightens our concern about what the combined affect of the retirements will be.

Q. Is there any other generations besides the

FirstEnergy generation that you were thinking of with that reference?

A. No, I don't think so. It was more of a general statement with the experience we had here in Ohio and now it looks like we got the potential to repeat it so it gets me concerned again.

Q. I'm flipping through to make sure I don't have anything else. That may be it, just one moment.

Those are all the questions. Thank you very much, Mr. Bradish.

A. Sure, you're welcome.

MR. MILLER: Kevin, I think you're up.

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EXAMINATION

BY MR. MOORE:

Q. Hi, Mr. Bradish, my name's Kevin Moore, I represent the Ohio Consumers' Counsel.

A. Hello, Kevin.

Q. Can you hear me okay?

A. Yes.

Q. If you have any problems, just let me know.

MR. MILLER: Kevin, it's Chris, and I'm hearing myself twice. Maybe are you on speaker?

MR. MOORE: Yeah.

MR. MILLER: Is it possible to pull off of it, I think we're getting some feedback.

MR. MOORE: Is this better?

MR. MILLER: You sound taller and better looking.

MR. MOORE: Must have the wrong guy then. All right, I'll do it from here then.

MR. MILLER: Thank you.

MR. MOORE: I'm only going have one hand now.

Q. (By Mr. Moore) Earlier you talked about the PJM generation deactivation process. You said that the generation would have 90 days or has to give a 90-day notice; is that right?

A. I think that's correct.

Q. So could you just explain to your knowledge what PJM does after they receive a notice of deactivation?

A. My understanding they'll do a detailed reliability analysis to look to see if there are any problems created on the grid as a result of that plant retiring. If they find none, then no problem, you're good to go.

If they do find problems, then they inform the generator of the problems and my understanding from there is that eventually they will offer the generator at some point a possible RMR contract to keep them continually running until they did get the reliability problems addressed.

Q. How much is the RMR contract worth or for? How is that determined?

A. I don't have any experience with that. I don't know.

Q. Do you know how long the RMR contract lasts for?

A. I don't know that there's a time limit associated with it. I think if parties agree, it can last until the transmission upgrades are put in place that will allow the plant to retire.

Q. Do you know of any reason why a generation owner would not want to accept an RMR contract?

A. I can't opine on that. I don't have any particular experience with those contracts.

Q. Okay. Just to be clear, someone might have asked this earlier, but in conducting your transmission impact study you used the 2019 RTEP base case; is that correct?

A. Yes.
Q. And then the RPM 2017-2018 base case model.
A. It was a sensitivity analysis.
Q. Did you use any other PJM models or cases?
A. No.
Q. Are you familiar with the, I'm sure you are, the RTEP process?
A. Yes.
Q. Can you explain or describe what the RTEP process is?
A. Generally speaking, it's a process that PJM runs through to assess the grid, assess the reliability performance of grid. And usually what they do is they look at five years, so in 2014 they would have put together a case that looks out five years, that's why we have 2019, and they do an assessment of the grid to see if there are any potential liability issues and to the extent there are, they go through a process where they get those reliability issues addressed.
Since Order 1000, those part of that process involves the competitive windows that they open up to have people compete for solutions on some

of the problems that they find, so that's, like I said, an annual process, it just runs continuously.

Q. As part of that process does the PJM study have a generator retirement that could lead to a reliability problem?

A. Not generally. Usually they don't study those until the generator tells PJM they want to retire.

Q. And so what types of issues is PJM looking into in this RTEP planning process?

A. Well, they're looking to see if as the system is modeled in the future if it will pass the reliability criteria. So they'll run a series of reliability to make sure it passes the criteria.

Q. So, for example, to see if a transmission line could carry a maximum amount of electricity, would that be something they'd look at?

A. No, they're just, they've got a representation of what they think the future looks like based on load forecast and other things and they just do an assessment to see whether or not the system as planned or as proposed for 2019 passes the reliability criteria.

So they look to see if all the

transmission lines, loading on the transmission lines are within their ratings, the voltages are within the appropriate limits, and to the extent they are not, then folks propose solutions to address those issues.

Q. So part of that forward-looking process does not involve generation retirement?

A. Yeah, so PJM does not look at generators retiring unless the generator tells them they are going to retire.

Q. If you could turn to page 4 of your testimony, lines 6 through 8.

A. Okay.

Q. You talk there about exporting of power. What parts of Ohio are exporters of energy or power?

A. I couldn't tell you. It's hard, that's a hard question to answer. Maybe you could be a little bit more specific?

Q. Okay. Well, I mean, you state that "When a plant is removed from the system, the specific location that was historically an exporter of power now must import power from other parts of the system to maintain the balance of supply and demand."

I'm simply wondering if to your knowledge you know if a part of Ohio is currently in that exporter of power?

A. So if there is a plant there, so back to what I said in my testimony, if there is a plant there and the plant goes away, there used to be power coming from that plant, now there's no power coming from that plant. So it used to be exporting power and the point being that the plant is now gone, that area that that plant was serving is now going have to import that power from somewhere else.

Geographically within the state of Ohio I don't know all the places that are imported and exported. You'd have to kind of define the area and do an assessment of load and generation in that particular area.

There are certain areas within the state of Ohio where generation seems to be concentrated and one of those is along the Ohio River in Southeastern Ohio. There tends to be a lot of generation along the Ohio River so it tends to -- that part of Ohio would export but generally you'd have to look at -- you'd have to kind of define the area and look at load resource balances within those areas to make that decision.

Q. Okay. Would the PJM planning process

you've spoken about earlier today account for an area, a specific location losing a generator and now instead of exporting having to import power?

A. So again, if a unit retires, then PJM would absolutely model that unit as retired and so that area would no longer be exporting, it would be importing and PJM would model that area as an importing area.

Q. Okay, thank you.

On page 5, line 2 of your testimony you state "The fewer options available, the more the grid is susceptible to swings in power flows, voltage, and frequency that can lead to system instability."

What do you mean by the "fewer options available"?

A. So again, here I'm talking about kind of the sentence before that where I'm talking about renewable generation and the ability to redispatch. So as you add additional nondispatchable generation into the environment and move dispatchable, that means you have fewer options, fewer dispatchable units from which you can control the grid.

The grid is a very dynamic process, grid operations. Every second, every few seconds we are pulsing generators up and down to maintain system frequency and voltages.

So you've got to have a set of resources on the grid that you can pulse up and down continuously in order to do that. So as we remove dispatch from generation and replace it with nondispatchable generation, we have fewer and fewer of those resources available to pulse up and down to maintain the grid.

So the issue then is one of you have concerns then about you can get much higher swings in power flow, you can get voltage swings, you can get frequency deviations that you can't manage, and ultimately those are bad enough we can lead to system stability problems. So that's in a sense what I'm talking about.

Q. Okay, thank you.

I think you spoke about load shedding earlier with Mr. Fisk. Can you explain how load shedding impacts our residential load?

A. Yeah. It basically cuts the power to that load.

Q. And this is something AEP currently practices?

A. We only do that in emergency situations. So the concept there is in situations where your grid is getting into trouble and you're getting to a point where you may be, you know, unstable and possibility of cascading, it's kind of like you want to stop the cascading so you shed load to prevent the entire system from cascading. So, no, it is not something we do on a regular basis, it's used in emergency situations.

Q. And what tools or mechanisms are put in place to avoid load shedding then?

A. We build transmission to make sure the transmission system is robust enough to handle the changing conditions on the system.

Q. What could be done in an emergency situation?

A. To avoid load shedding?

Q. Correct.

A. At that point you're stuck with whatever you got. So --

Q. There's no other -- I'm sorry, go ahead, finish your answer.

A. No, that's all right.

So the operators will do everything in

their power before they shed load. So the last answer is to shed load. So you redispatch the system as much as you can, you do switching, you try and reconfigure the system as much as you can to avoid the problems.

So redispatch generation, you'll try and maybe change some switching configurations to relieve some problems, but at the end of the day if those two options don't work for you, the last thing you've got to control is load. So you can control the supply, you can control the configuration of the grid, and then ultimately you can control the load. So the load is the last option.

Q. Okay. Page 7, lines 18 through 20 of your testimony, you state that "In some cases, the power flow models did not converge, which is an indication of severe system reliability concerns."

Can you explain by what you meant by "the power flow models did not converge"?

A. Basically they can't find a solution that's acceptable. There's no solution that works. So literally the program will not solve for those conditions.

Q. Does that mean that there is not a

possible solution in reality or just that this model that you're running couldn't find one?

A. I think there's not a solution that works for that particular configuration.

Q. So what would system planners do in that situation?

A. They will start adding in transmission reinforcements. So they'll try and assess where the problem is on the grid, they'll try and find out what transmission lines may be overloading, what areas where the voltages are collapsing, and then they'll try and provide transmission solutions that move power away from that area.

Q. Give me just a minute here.

Okay, I have no further questions. Thank you, Mr. Bradish.

A. You're welcome.

MR. MILLER: Matt, do you have any?

MR. PRITCHARD: I do not.

MR. MILLER: I think that leaves to us Mr. Beeler's question.

MR. BEELER: Have a good weekend.

MR. MILLER: Is everybody done?

MS. FLEISHER: We're good. Thanks,

everybody.

(Whereupon, at 3:17 p.m., the deposition was concluded and signature was not waived.)

AFFIDAVIT

State of Ohio   )
) SS:
County of _______________)

I, ROBERT W. BRADISH, do hereby certify that I have read the foregoing transcript of my deposition given on Friday, September 25, 2015; that together with the correction page attached hereto noting changes in form or substance, if any, it is true and correct.

____
ROBERT W. BRADISH

I do hereby certify that the foregoing transcript of the deposition of ROBERT W. BRADISH was submitted to the witness for reading and signing; that after he had stated to the undersigned Notary Public that he had read and examined his deposition, he signed the same in my presence on the ________ day of ______________________, 2015.

____
Notary Public

My commission expires _________________, ________.

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CERTIFICATE

State of Ohio)
) SS:
County of Franklin)

I, Julieanna Hennebert, RPR and RMR, the undersigned, a duly qualified and commissioned notary public within and for the State of Ohio, do certify that, before giving his deposition, ROBERT W. BRADISH was by me first duly sworn to testify to the truth, the whole truth, and nothing but the truth; that the foregoing is the deposition given at said time and place by ROBERT W. BRADISH; that I am neither a relative of nor employee of any of the parties or their counsel and have no interest whatever in the result of the action.

IN WITNESS WHEREOF, I hereunto set my hand and official seal of office on this 28th day of September, 2015.

Julieanna Hennebert, RPR, RMR,
and Notary Public in and for the
State of Ohio.

My commission expires February 19, 2018.

(79226-JLH)

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ARMSTRONG & OKEY, INC.
Registered Professional Reporters
222 E. Town St. - 2nd Floor
Columbus, Ohio 43215
614/224-9481

September 28, 2015

Robert W. Bradish
c/o Chris Miller
IceMiller/AEP

Re: In the Matter of Ohio Power Company 14-1693-EL-RDR & 14-1694-EL-AAM

Dear Mr. Robert W. Bradish:

Enclosed is the transcript of your deposition taken on September 25, 2015, for examination pursuant to 4901-1-21(K) of the Ohio Rules of Practice before the Public Utilities Commission of Ohio.

The rule requires that your deposition be read by or to you. Any changes in form or substance which you desire to make shall be entered by me with a statement of the reasons given for making them.

If your deposition is not signed within 10 days of its submission to you, I am required to sign it and state the fact of the refusal to sign with the reason, if any, given therefor; and the deposition may then be used as though signed, unless on a motion to suppress the Commission holds that the reasons given for the refusal to sign require rejection of the deposition in whole or in part. By copy of this letter I am advising the attorneys in the case of the submission of your deposition.

Please have your deposition signed <u>in the presence of a Notary Public</u> and return to us by certified mail.

Thank you for your promptness in this matter.

Sincerely,

ARMSTRONG & OKEY, INC.

Cc: Fisk, Moore

AFFIDAVIT

State of Ohio)
) SS:
County of ________________)

I, ROBERT W. BRADISH, do hereby certify that I have read the foregoing transcript of my deposition given on Friday, September 25, 2015; that together with the correction page attached hereto noting changes in form or substance, if any, it is true and correct.

____
ROBERT W. BRADISH

I do hereby certify that the foregoing transcript of the deposition of ROBERT W. BRADISH was submitted to the witness for reading and signing; that after he had stated to the undersigned Notary Public that he had read and examined his deposition, he signed the same in my presence on the ________ day of _______________________, 2015.

____
Notary Public

My commission expires __________________, ________.

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ERRATA SHEET

Please do not write on the transcript. Any changes in form or substance you desire to make should be entered upon this sheet.

TO THE REPORTER:

I have read the entire transcript of my deposition taken on the _______ day of _____________________, ________, or the same has been read to me. I request that the following changes be entered upon the record for the reasons indicated. I have signed my name to the signature page and authorize you to attach the same to the original transcript.

Page	Line	Change	Reason

Date ____________ Signature: ___________________________________

CERTIFICATE

State of Ohio)
) SS:
County of Franklin)

I, Julieanna Hennebert, RPR and RMR, the undersigned, a duly qualified and commissioned notary public within and for the State of Ohio, do certify that, before giving his deposition, ROBERT W. BRADISH was by me first duly sworn to testify to the truth, the whole truth, and nothing but the truth; that the foregoing is the deposition given at said time and place by ROBERT W. BRADISH; that I am neither a relative of nor employee of any of the parties or their counsel and have no interest whatever in the result of the action.

IN WITNESS WHEREOF, I hereunto set my hand and official seal of office on this 28th day of September, 2015.

Julieanna Hennebert, RPR, RMR,
and Notary Public in and for the
State of Ohio.

My commission expires February 19, 2018.

(79226-JLH)

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