PLACE: Dobbs Building
Raleigh, North Carolina
DATE: Friday, July 19, 2019
DOCKET NO.: E-100, Sub 158
TIME IN SESSION: 9:31 A.M. TO 12:58 P.M.
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Lyons Gray
Commissioner Daniel G. Clodfelter

IN THE MATTER OF:

Generic Electric

Biennial Determination of Avoided Cost

Rates for Electric Utility Purchases

from Qualifying Facilities - 2018

Volume 7

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T A B L E O F C O N T E N T S

E X A M I N A T I O N S

PAGE

PANEL (Cont'd.)

JEFF THOMAS, DUSTIN METZ, JOHN R. HINTON

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: Okay. Let's go back on the record.

MS. BOWEN: Madam Chair, if I may, before we get started back on cross, I have one just housekeeping matter, if that's all right.

CHAIR MITCHELL: Okay.

MS. BOWEN: Okay. Great. Yesterday we moved Ms. Glick's testimony into the record as if -- prefiled testimony into the record as if given orally from the stand. That was the testimony filed on July 3rd, 2019, consisting of 15 pages. I think it was a little unclear whether we had officially moved her exhibit into the record, so I just would like to make that clear for the record. At this time we would move her exhibit that was prefiled -- that was premarked as Glick Exhibit A and prefiled with the Commission on the same day, July 3rd, 2019, consisting of four pages, into the record, as well as her testimony.

CHAIR MITCHELL: Without objection, the motion is allowed.

MS. BOWEN: Thank you.

(Whereupon, Glick Exhibit A was admitted into evidence.)

MS. FENTRESS: Madam Chair, if -- I also have a housekeeping matter that I could address right now if --

CHAIR MITCHELL: Please do.

MS. FENTRESS: Thank you. I believe on Monday Commissioner Clodfelter asked the Duke Panel if we would prepare a late-filed exhibit calculating the Sub 158 rates using the original inputs that we filed with, but under the stipulated rate design. We have done that calculation, and we have the exhibit and we can pass it up, if you would like.

COMMISSIONER CLODFELTER: The other -- that's great. I don't -- I also sort of said you could update the market price -- current market price of gas.

MS. FENTRESS: Oh, yes. For the -- for the 20-year avoided cost rate.

COMMISSIONER CLODFELTER: For the 20-year rate.

MS. FENTRESS: Yes, sir.

COMMISSIONER CLODFELTER: And --

MS. FENTRESS: We do not have, actually, the 20-year avoided cost rate calculated yet, nor do we have the operating reserves information that you requested.

COMMISSIONER CLODFELTER: I understand that. Right.

MS. FENTRES: Our -- the -- one of the

employees of Duke that manages that information is currently chairing the NERC Resources Subcommittee on Balancing and Reliability Standards, which is a continental organization, and so he is doing that at the moment --

COMMISSIONER CLODFELTER: That's fine.

MS. FENTRESS: -- and we will get that information from -- or he will be doing that, and we'll get that information as quickly as we can, but I only -- I'm afraid I only have the one exhibit.

COMMISSIONER CLODFELTER: Okay.

MS. FENTRESS: Thank you. Can I pass that out?

CHAIR MITCHELL: Please do.

MS. FENTRESS: Thank you.

CHAIR MITCHELL: And Ms. Fentress, how would you like this exhibit to be marked?

MS. FENTRESS: Duke Energy Late-Filed Exhibit Number 1.

CHAIR MITCHELL: It shall be so marked.

COMMISSIONER CLODFELTER: There's going to be a bunch more.

MS. FENTRESS: Madam Chair, I was just going to pass them out, and I don't believe there's anything else that I was going to do at this moment.

CHAIR MITCHELL: Okay. Just giving everyone an opportunity to review briefly. Ms. Fentress has moved that Duke Energy Carolinas Late-Filed Exhibit Number 1 be accepted into the record. Unless there are objections to this motion, the motion shall be allowed. All right. Hearing no objections, the motion is allowed.

MS. FENTRESS: Thank you.

CHAIR MITCHELL: Thank you, Ms. Fentress.

(Whereupon, Duke Energy Late-Filed Exhibit Number 1 was marked for identification and admitted into evidence.)

MR. SMITH: And just one more piece of housekeeping, similar to SELC's, we had an exhibit attached to NCSEA Witness Tom Beach's direct testimony that was marked and also Exhibit 1 from NCSEA Witness Tyler Norris, his supplemental testimony, I believe, or supplemental responsive testimony that was marked. I'd like -- NCSEA would like to formally move that those two exhibits be entered into the record now.

MS. FENTRESS: With no objection.

CHAIR MITCHELL: Without objection, those -- that motion is allowed.

MR. SMITH: Thank you.

(Whereupon, Beach Exhibit 1 and
Norris Exhibit 1 were admitted into
evidence.)

MS. HUTT: Maia Hutt representing SACE.

JEFF THOMAS, DUSTIN METZ, JOHN R. HINTON;

Having been previously sworn,
Testified as follows:

CONTINUED CROSS EXAMINATION BY MS. HUTT:

Q Good morning, Mr. Thomas. So I'm so sorry to do this, but I'd like to go back to discussing the LOLE FLEX metric, if you don't mind. So as I understand it, the premise of the Astrapé model is that if LOLE FLEX is allowed to increase substantially, it is expected that NERC CPS1 and BAAL standards will be violated more often.

A (Thomas) Yeah. I would agree that the two standards are correlated.

Q So balancing deviations aren't always bad, right?

A That is correct. It depends upon the frequency of the interconnection.

Q And does the study account for that?

A No, it does not.

Q So it's possible that you could have a series of five-minute periods of imbalance that do nothing to impact your CPS1 compliance, right?

A Witness Metz may have more to expand on this, but it -- it is possible, although once again, as discussed in this proceeding, modeling the frequency of the entire interconnect is not a realistic modeling exercise and, therefore, using a LOLE FLEX standard as a proxy that correlates with NERC standards is, I think, appropriate.

Q Thank you. Yeah. So I guess I'm not -- I'm not trying to suggest that they're not correlated. I'm just trying to go to some questions that suggest that there are some cases where that correlation doesn't follow through. So, for example, if you have an algorithm that is spitting out the right answer, in most cases there are often edge cases where the algorithm doesn't work, and that's why you need to strengthen the reliability of your algorithm?

A Could you just restate that question? I'm not sure I exactly followed.

Q Sorry. I guess I'm trying to explain where this question is coming from. My understanding is that when you're building an algorithm, like to try to get an answer to a question, you're trying to solve for something, the reason that it's difficult to build good algorithms is that you often have edge cases or cases that you need to be more specific in your model in order to account for. So I'm just trying to probe what are those potential edge cases? What are the cases that don't always translate to -- yeah. Does that make sense? If it doesn't, that's okay.

A Yeah. I think -- if I'm following you right, I mean, the future of any program models is, of course, that sometimes there are these situations where the model will go all in on a certain variable or value, but I think that what we did in requesting additional analysis from Duke, particularly having them loosen the LOLE FLEX model, is that it showed us that there -- the model was, to a certain extent, robust to the metric that was the reliability metric that was chosen, and what truly mattered was the difference between the base case and the change case. So my -- my Exhibit C that we've gone over before does -- looks at what happens when you change the LOLE FLEX. You know, does it have a radical impact on the amount of reserves that are required to be held. And we found that it really didn't. And that -- that really is -- it corresponds exactly with what the Idaho study had stated, that the -- the reliability metric chosen is relatively immaterial. It is the difference between the base case and the change case that is truly important.

Q Thank you for that clarification. So just to confirm, there are situations where you could have a series of five-minute balancing deviations that do nothing to impact either your BAAL score or your CPS1 score, just as a matter of possibility?

A (Metz) I mean, I think it might be argumentative of how you define impact and, again, of how the system operators are actually going to be dispatching the system. Now, you could say in a 30-minute interval for a BAL-001 that a violation didn't occur, that might be true up to the 30-minute time period. But, again, the system operators are working on the system. They're not waiting at minute 20, they're not waiting at minute 15. AGCs, there's other dynamic natures taking place. And there's other BAAL considerations to take into consideration. I believe Witness Holeman -- Hillman (sic) in Sub 148 from Duke provided other examples, I believe it was BAL-002, where it looked at a contingency reserve requirement being -- had to be resolved within a 15-minute interval, restoring the ACE back to essentially zero before the pre-condition occurred. So while we balance how many -- what is the correct interval step, whether it's 30 minutes, five minutes, 15 minutes, the system operators are taking actions in those interim in real time.

Q Thank you.

A (Thomas) If I can just elaborate a little bit, I think the LOLE FLEX metric is -- while it is a correlated proxy with the NERC standards, it is not the same thing. The NERC standards look at five-minute intervals without perfect foresight, with the operators chasing this uncertainty. The LOLE FLEX metric looks at five minutes out, does the system have the capability to meet that perfectly known load. And if that ability of the system to react does not exist, then that is a violation. It is the difference between playing -- betting on sports with and without an almanac from the future. I mean, you know, it's just a different standard, a different methodology.

Q Thank you. So my understanding is that adding operating reserves is not the only way to maintain reliability as solar penetration increases; is that right?

A Mr. Metz may expand on this. I'm not a system operator, but I know that having the reserves available to meet that demand is a significant way, but there may be other ways to operate the system to handle that volatility.

A (Metz) So if you're saying in a hypothetical that energy storage could reduce the volatility, so, again, the component that we're trying to solve here is the incurred cost on to the system as volatility, yes, there are other mechanisms in place that can be incorporated by the QF to reduce the overall volatility and increases value to the system and to the grid.

Q Thank you. So I'm thinking of page 47 of the Astrapé study where it says at higher levels of solar, the impacts might -- may be better mitigated by adding additional flexible generation rather than solely increasing load following reserves. So the study did not look at those. And I'm wondering if the Public Staff conducted any analysis to determine whether options, like adding flexible generation, would be more cost effective than simply adding more load following reserves.

A (Thomas) We did -- in part of our investigation we did not ask Astrapé to run additional models with a different system. We asked them to run the models with the system as is. However, part of the update process would be that the system modeled in the Astrapé study is updated to match the system that Duke actually has, so that might reflect the retirements of older, more efficient, slower ramping units and the addition of faster ramping, perhaps, CTs. And in addition, I would just point out that, you know, in -- we have supported studies of the system and energy storage and how it may impact the grid and reliabilities in other proceedings as well.

Q Just one last question. So as I understand it, the model is adding reserves in response to -- is adding reserves all the time, so year round, in response to violations; it's not adding reserves just to time periods that are identified as risky, is that right, or likely to result in a violation?

A I believe that the reserves that are added are -- are averaged throughout the year, and they may vary hourly. That's my belief, subject to check. It's not like they necessarily will add reserves at night to accommodate solar deviations, but subject to check, I'd have to look back at some of my information.

Q Okay. And did the Public Staff conduct any analysis to determine whether adding those reserves in a more targeted manner would be more cost efficient?

A We did explore a little bit with Astrapé whether adding different types of reserves might be more efficient in terms of reducing the cost of carrying those reserves, but as far as exploring the exact hours and -- and a more targeted addition of reserves, I think maybe you were referring to Witness Johnson's testimony or affidavit, we did not specifically ask for that analysis.

Q I apologize. I actually have just a couple more questions, but go ahead.

A (Metz) I was just -- again, the emphasis is looking at the base case and then looking at solar volatility added to the base case, so the cost that's differed is based upon the system, how it's operated now. I believe Mr. Thomas can correct me, but if you look at the Idaho study, the ancillary services or the reserves used to ramp up and ramp down, they restrained the model to only look at hydro as the capacity resource for dispatch. So, again, the base case scenario is how the Duke utility system is now, and that's one reason why we highly support the refresh. As the system evolves, we can continue to get the best number out there.

Q Thank you. So just to ask a couple questions about the base case, I believe that Mr. Wintermantel's testimony was that the way Astrapé and Duke validated their model was to compare the reserves required in the no solar case against the historical reserves in 2015; is that your understanding as well?

A (Thomas) Yes. That's -- that's what we had asked for, and that's my understanding.

Q And so their conclusion was that since the reserves required in the no solar case matched the historical reserves in 2015, that shows that the model is pretty accurate?

A It wasn't an exact match, but they were quite close. I think it was 1,660 versus 1,600 and, yeah, that was used to -- to validate the results of the base case.

Q So as I understand it, in the year 2015 North Carolina became the fourth state in the nation to surpass 1,000 MW of solar; is that right?

A Subject to check, I'll accept that.

Q So given that there was a not insignificant amount of solar on Duke's system at 2015, wouldn't you expect the reserve requirements calculated for the model in the zero solar scenario to be significantly lower than the historical reserves from 2015?

A Well, the model calculated approximately 60 MW less reserves than was actually found in 2015. And as we've seen in the model itself, adding 840 MW of solar in DC only increased the load following reserves by about 26 MW. So it was expected that the model would predict lower reserves than -- than in real life, and that is what we saw, but it was still close enough for us to believe that the model was a reasonable attempt to quantify this charge and that the claim that the LOLE FLEX metric was tens of thousands of times too stringent was -- just was not supported by that calibration.

A (Metz) And just one thing to add is looking at the -- that level over the year -- I don't know what number you're referencing in terms of the 1,000 MW -- what time period did the 1,000 MW come in? Did they come in approximately at the end of the year when we typically see a rush of interconnection facilities being incorporated? Therefore, that 1,000 MW, if you looked at it in 2015 may be misleading or not painting the full picture of the overall analysis.

Q Okay. Thank you.

MS. HUTT: I think my colleague, Ms. Bowen, has some questions for Mr. Metz.

CROSS EXAMINATION BY MS. BOWEN:

Q Good morning, Mr. Metz.

A (Metz) Good morning.

Q I want to talk about your prefiled testimony in this proceeding. And I appreciate that you did a good job sort of walking through the phrases material modification and material alteration. And I think, as we all acknowledged yesterday, we've had lots and lots of filings and testimony about these phrase -- these two different phrases, material modification and material alteration. There's also, as you've correctly pointed out, overlap with the North Carolina interconnection proceeding in that the definition included, in those procedures, interconnection procedures, raw material modification. So I just want to make sure we're all on the same page as to where we are at this point in time in the proceeding in terms of the Company's terms around material modification and material alteration. Can you help me with that? And I can ask specific questions.

A Specific questions would be nice.

Q Okay. Great. So -- and you go through this -- this distinction on I believe its page 11 and 13 of your testimony. And my understanding is now the Company has changed the term that they're using in the PPA context from material modification to material alteration. Do I have that right?

A For the current standard offer, yes, they are looking to incorporate the term material alteration.

Q Okay. And then they -- I believe initially there was some concern regarding the initial filings about the Company having some sole discretion around that

-- what constitutes material modification. Do I have that right?

A I believe that's a fair characterization.

Q Okay. And then with -- in some of the subsequent filings the Companies, and I mean Duke specifically, have said, okay, we're -- we've heard the Public Staff, we are willing to say commercially reasonable discretion of the Utilities, rather than sole discretion. Do you recall that?

A Yes. And I believe Mr. Hinton covered some of that in his testimony as well.

Q Yeah. Great. Okay. To the best of your knowledge, the -- so where we are today in this proceeding with the Company's revisions to -- the initially proposed revisions to the PPA contract, are there still some places where the Company is given sole discretion in this -- in terms of, you know, material alterations to a facility?

A I believe how the commercial terms and conditions for a material alteration is defined, or it's better defined than the NCIP material modification, as I outlined in my testimony. I mean, I do believe there is a subjective terminology of how one can quantify impact. But with that said, I believe that it is the Utility's responsibility to validate the impact, as they are the system operators of the electrical grid.

Q Okay. And then specifically -- I don't know if you have it in front of you, and it's probably okay if not, you can say subject to check -- but in my understanding, this is the latest language proposed by the Utilities in their revised PPA. This is, subject to check, their reply comments filed March 27th, 2019. Exhibit 4 has their new redlines. You all might -- it looks like Mr. Thomas might have it. And page -- I'm looking at Exhibit 4, page 20.

A If you can provide a copy, please.

Q Yes. Absolutely.

MS. BOWEN: Madam Chair, may I approach?

CHAIR MITCHELL: Yes.

Q And I think just probably the easiest way to do this, I do have just some brackets there. Do you see the bracketed paragraph?

A Yes. One second. I'm just reading over, putting in context. We were talking about the contract capacity and just reading through.

Q Great.

A All right. Go ahead.

Q Will you read the number of that paragraph for me?

A So talking about Section 4 or bullet 4, Contract Capacity, it's either (d) or (e) because -- little (d), then later little (d) is struck through to (e).

Q Okay. Great. I just want to make sure your counsel has got it, too.

MR. DODGE: We were just looking back to material alteration.

MS. BOWEN: Okay. Great.

Q Okay. Great. And I do see where it's marked. It's a little confusing, is it (d) or (e) now? So if you'll just read that paragraph so we've got it in the record. I know it's in the record, but just so -- so we can talk about it for a minute, that would be great.

A Okay. "Any Material Alteration to the Facility, including without limitation, an increase in the Existing Capacity, a decrease in the Existing Capacity by more than five percent or the addition of energy storage capability shall require the prior written consent of the Company, which may be withheld in the Company's sole discretion, and shall not be effective until memorialized in an amendment executed by the Company and the Seller."

Q Thank you, Mr. Metz. So my concern is that we've heard that the Companies have changed the definition of material alteration, but I think that this other provision still gives them sort of sole discretion to deny material alteration. And so I may be missing something, but I know you took great pains to sort of separate out, you know, when we're talking about material modifications versus alterations. I just want to make sure there are other -- and there may be others, you know, where there are other instances of the Utilities getting sole discretion that were not -- that we haven't changed one part of the terms and conditions, but have not caught the other ones. So could you help me -- could you just explain, has that -- has that provision, to your knowledge, been proposed to be revised by the Companies or if -- or, you know, anything else you would add on that?

A To my knowledge, no. Just saying on page 10, material alteration in my testimony was defined, understanding that there was some interpretation there, but I believe the Company agreed to revise the definition for more clarity.

Q So would the Companies be revising the definition of material alteration, which is the phrase we're now using in this context, or are they also agreeing to, to the best of your knowledge, to also address the other places where its referencing sole discretion?

A It is my understanding the term material alteration will be better defined for more clarity, but I'm trying to say to the extent that someone wants to add energy storage and increases or by parameters set by the definition of material alteration, that they should notify the Company. So I'm -- I'm not drawing a line between how the use of material alteration in the contract term is out of line with the definition and how the Utility shall be notified.

Q Well, they shall be notified, I think it says, and you do have my copy, but something along the lines of they -- they can deny it in their sole discretion.

A Well, I believe that would be the case of anything that's modeled or studied to the -- to the extent of the Utility.

Q So I know the -- the Public Staff and Duke has entered --

MS. BOWEN: Okay. Thanks. Well, I'll just come get it in a second. I think -- I think we're done with that one.

Q So I know the -- the Public Staff and Duke Carolinas, Duke Progress, have entered into a Stipulation regarding the solar integration charge that we've talked a lot about, and you're familiar with that Stipulation?

A Yes.

Q Okay. And that Stipulation also considers when -- what happens when a QF adds battery storage; is that right?

A If you're referring to the off ramp or the SISC charge could be potentially waived, then yes.

Q And -- and that does -- my understanding is that the Stipulation does allow for some -- there are some terms -- there are some parameters around the Utility's discretion, but it does include a phrase about reasonableness. Do you want --

MR. DODGE: Madam Chair, if I could object to the form of the question. If Ms. Bowen could provide either some specific line numbers --

MS. BOWEN: Sure.

MR. DODGE: -- or some definitions she's referring to for the witness, please.

MS. BOWEN: Sure.

CHAIR MITCHELL: I'll sustain the objection.

MS. BOWEN: Sure. If you'll give me just a moment, then I'll get it for him. That's all right. I can actually withdraw that question. I believe it's in the record in the -- in the Stipulation itself, and that's been filed, so I'll withdraw the question, thank you, just to save us time.

Q So then the only -- I have just a couple more questions. It should be fairly quick. In your testimony, supplemental responsive testimony on page 3 and 4, supplemental testimony, you talk about -- and I think -- and just to preface this, I think this gets at the heart of -- of your testimony. You're -- you're looking at the provisions being proposed around battery storage, what's reasonable, what's not reasonable, what are the definitions. And you say -- or you acknowledge some of the positions that have been articulated by the Utilities in this proceeding would, in your opinion, frustrate the addition of battery storage. So that's what you're -- you're seeking to flesh out in your testimony where that might be the case. Do I have that right?

A Yes. That's correct.

Q Okay. Thanks. And then -- and you recognize here to storage -- that storage has the potential to provide system and retail customers benefit if the existing solar facilities were able to use storage to either shift some of their -- their output away from those times when the sun is shining or to smooth the delivery of the energy during times of sporadic sunshine. Do I have that right?

A Yes. That's correct.

Q Okay. Great. And Mr. Metz, have you -- have you been here for most of the proceeding? Were you here on Monday, specifically?

A Yes, I was.

Q Okay. So you may have heard me ask Duke Witness Snider about the intent behind PURPA. Do you recall those questions?

A Vaguely.

Q Okay. Well, subject to check if you need to, but the -- the intent and the language in PURPA is meant to encourage the development of QF power, small power producers and cogen facilities. Would you agree with that?

A Can you repeat the question?

Q Sure. And we can get the exact language, if you like. So subject to check, if you need -- if you need to, but Section 210 of PURPA was intended to encourage cogeneration and small power production?

A Yes.

Q Okay. And the Supreme Court -- US Supreme Court has recognized that the -- has also recognized this intent and that the use of -- increased use of sources -- these kinds of sources of energy, so renewable energy resources that qualify, would reduce the demand for traditional fossil fuels. Would you agree with that -- that, generally, subject to check, if you need to?

A Subject to check.

Q Okay. And it recognized that -- the Supreme Court has recognized that electric utilities had -- and the Congress recognized, excuse me, that traditionally, electric utilities have been reluctant to purchase power from and sell power to non-traditional facilities. Would you agree with that?

MR. DODGE: Madam Chair, if I could object again. I think that this is asking for a legal interpretation or information about interpretation or the meaning behind PURPA's -- Congress' implementation of PURPA. So if she has some specific language, if Ms. Bowen has specific language she'd like Mr. Metz to agree that that's what the language says, I think that would be appropriate, but asking him to respond to her characterization of that, I think, is -- is not a proper form of a question.

MS. BOWEN: I was just quoting the Supreme Court, but I think since we have gotten it into the record already, I'm happy to withdraw the question. Thank you. And I don't have anything further.

CROSS EXAMINATION BY MR. SMITH:

Q Good morning, gentlemen. My name is Ben Smith. If I -- I believe I met all of you, but if I haven't, I'm Regulatory Counsel for the North Carolina Sustainable Energy Association. I apologize for the angle here, but a lot of stuff on the table, so -- I realize we carved 10 minutes out for each of you in this cross, but I think any one of you can answer these questions, as appropriate. Also, I'd like to say that for context, some of your answers yesterday were very helpful for me and provided context and completely changed my cross, so you gave me a lot more work.

Okay. So first I'd like to talk about the solar integration charge, and then I'm going to get into the Astrapé model, and particularly the implementation of the solar integration charge. Am I correctly characterizing your testimony yesterday, I think it was Mr. Thomas who said this, that it is -- that Public Staff's position that the solar integration charge is not a standalone line item charge, but rather a decrement or reduction to the avoided cost rate?

A (Thomas) Yes. That's the position that we've taken in our initial comments, that the SSIC is a component of the avoided cost, the decrement as allowed by PURPA, but should not be rolled into particularly like the avoided energy rate.

Q Okay. And I can't recall whether this question was asked or -- there's been a lot going on, but -- and maybe you were not in the room at the time, but do you know, and this might have been discussed when the Stipulation was made, whether Duke also takes the position that the solar integration charge is a line item -- I'm sorry -- is not a line item standalone charge and that they agree with you that it's a reduction in the avoided cost energy rate?

A Can you point to testimony or are you referring to a specific line or --

Q I'm not. This is more to take -- I'm curious as to whether this was discussed during the Stipulation. And when I say during the Stipulation, I'm asking when you all -- you have referenced in your testimony that you've talked with Duke and they were able to ease some of the issues. And this is an issue maybe not for you, but for me, and so I'm asking if that was discussed.

A I don't recall during the -- I'm not comfortable discussing the Stipulation discussions directly, but I do know that -- I believe that this issue was resolved in Duke's reply comments where they kind of agreed that it should not be a decrement to the avoided energy rate, but rather would be a decrement to the avoided cost. And we had also expressed just some concerns about the SSIC collected from QFs would be flowed back to ratepayers via the fuel charge we had -- we had wanted to be a -- kind of a separate credit to fuel -- to ratepayers on the fuel rider instead of rolling it into the avoided energy charge. And I thought they had agreed with us, but Bob -- Mr. Hinton may have something.

A (Hinton) No. I'm just going to add, one of the obvious reasons why we wanted to have a separate charge is because we use avoided cost for other applications, such as DSM and EE, and to have it rolled into energy would be problematic.

Q Okay. And that gets to what -- a lot of what I'm about to talk about, discuss this, and thank you for that. And, again, apologies. I am -- this is -- this is a case where I don't know the answers to the questions

I'm asking, so I'm violating rule 101 of cross examination, but this is, honestly, exploratory. So yesterday you were asked whether the SISC would apply to the CPRE and GSA programs, and what I heard from you was that as it is currently situated and calculated in this docket, it does not apply to those programs, according to the Public Staff, correct?

A (Thomas) No. I think that's not quite where I was at. Obviously, in order for the SSIC to apply to any other docket, whether it be the CPRE Tranche 2 or the GSA program, obviously, the first thing is to be approved by the Commission, and then those programs also need -- have Commission oversight as well as to how that charge would be considered. I think the -- the point I was trying to make was that the Public Staff agrees that uncontrolled solar generators are imposing cost on the system and that to the extent that any developer or QF is connecting an uncontrolled solar generator to the system, if this charge is approved, they should be subject to that charge.

Q Okay. So would it be fair to say that subject to Commission approval in those other dockets, that the solar integration charge proposed here would then be applied to those proceedings, according to the Public

Staff?

A I believe that if -- if it's an uncontrolled solar generator that is participating in those proceedings, then, yes, they would have that charge be considered. Like I said, particularly with regard to the CPRE and applying that cost to both third-party and utility proposals, there's -- there's some complexities that arise there, but to the extent that it is an uncontrolled solar generator, that charge should be considered and only exempted for a controlled solar generator that is able to reduce their -- their burden on the system. And Mr. Metz may have...

A (Metz) Again, the premise there is just assigning cost to cost causers. I mean, that's generally what we're just getting at, to where we identify through modeling that we're -- cost is being imposed on to the system. We're just trying to keep ratepayers whole.

Q Completely understood. So I guess my question, then, and I apologize, but could you define what you mean by uncontrolled versus controlled solar generation there, because I do think that the CPRE docket does have some language that -- that allows for some control. And so I'm wondering what exactly you meant by that, Mr. Thomas.

A (Thomas) Just one second here. So just on --

on page 5 of the SISC Stipulation we -- the term controlled solar generator is defined, and we're generally talking about a generator that it can construct and operate its generating facility and storage to meet certain design and operational specifications, and essentially to reduce or eliminate need for ancillary services. So like we've talked about, just the ability of a utility to curtail the solar facility may not make that a controlled solar generator. When I talk about controlled, I'm speaking specifically to the definition that we've used in the Stipulation.

Q Okay. So the curtailment provisions in the CPRE docket wouldn't definitively apply to the solar integration charge, making the assumption that this charge goes to that docket?

A Yeah. I don't know that curtailment can necessarily reduce a solar facility's volatility, and the SISC is designed to recoup the cost of that volatility. So just being able to turn off or dial down a facility during certain times of the day is not necessarily going to reduce the volatility of that facility.

Q Okay. And I guess my last question on this topic is given that CPRE in particular is a marketplace and the idea is a competitive procurement process, do you believe the participants in any of the programs, including GSA, but particularly CPRE, should be able to provide feedback on both the inputs of the model and also its underlying assumptions, limitations, and validation of its simulation against historical data analyses?

A If I'm understanding your question right, you're asking if Intervenors and market participants are allowed to provide input to model. And I've read several hundred pages of that very input, and I believe that it's been provided in this proceeding, but also market participants have the ability to comment on the PPAs and particularly the energy storage protocol that we proposed in the CPRE program. But to the extent that the SISC is approved here, I believe that market participants, through the Intervenors, have extensively commented on the inputs and the assumptions in the model.

Q Well, yeah. So I think that might be where NCSEA disagrees with the position of the Public Staff and Duke, assumably, is that I don't believe that there is any language in the Stipulation or elsewhere that allows for Intervenors here or elsewhere to provide feedback in terms of the underlying model's assumptions, limitations, and validation. So I guess I'm asking you is where, either in the Stipulation or in the Astrapé study, it allows for participants, solar developers, who else, to make suggestions to change those underlying issues?

A So Mr. Metz may have something to add here, but the Stipulation does discuss the biennial refresh. The biennial refresh of the SISC will happen in each avoided cost docket every two years, and at that time, as the SISC is a component of avoided cost, all Intervenors or any party wishing to intervene can review the model, can make interrogatories of Duke Energy, can question and provide expert testimony to challenge the assumptions in the model. And the avoided cost proceeding is where those -- where that feedback would -- would take place. And it would not be taking place in, say, a CPRE docket or a pre-market RFP solicitation.

A (Metz) Yes. I agree with Mr. Thomas in that regard. Avoided -- avoided cost docket sets the avoided cost. It sets the relative ceiling for CPRE. I mean, to open up the avoided cost to dissect the total consideration, looking at all increments and potential decrements in CPRE, is outside its intent, in my opinion.

Q Thank you. And I'm going to get to the Stipulation because, Mr. Thomas, your answer was very interesting to me there. And I have some -- but I don't want to get past the House Bill 589 programs because I do

-- I just have a few more questions on those. On GSA, is it your understanding that this program, by statute, calls for 600 MW of solar to be put on the grid through a green rider, where a commercial customer or the University of North Carolina or the military, who have their own carve-outs, negotiates directly on price terms with a solar developer, correct?

A (Thomas) I would agree with the -- your characterization, except for the one caveat that the bill carves out the capacity, but it does not mandate that that capacity be added to the GSA program. It allows for any unutilized capacity rolled over into future competitive tranches, but it doesn't mandate 600 MW of GSA facilities to be put online.

Q Understood. And I'm sorry, if I said mandate, I didn't intend that. So my next -- oh, I'm sorry. And Duke would serve as an intermediary of sorts where, within the GSA construct, the commercial customer pays a normal electric bill, but the bill has a bill credit that applies to them based upon the price terms they negotiated with the developer, correct?

A I believe the bill credit is reflected as the avoided cost. The customer pays the negotiated price as an adder to their bill, so...

Q Yeah. That's right. I'm sorry. I misstated that. That's correct. And that bill credit is limited or is set at avoided cost. And within that docket, after much discussion and argument, there was -- the Commission determined that the customer could elect two different versions of avoided cost, correct?

A That is correct.

Q And one of those versions is strictly based upon the avoided cost determined in this proceeding, and I think they refer to it as the administratively determined avoided cost, correct?

A I believe that's correct, refreshed every five years, if I -- my knowledge of the Order is fresh enough.

Q Yes. Thank you. And the second avoided cost rate was based upon a settlement -- and I apologize, I know this is getting into the weeds, but I'm just trying to set it up for my final couple questions that do relate to the integration charge. The second avoided cost rate was based upon a settlement between Duke and Walmart which involved a different avoided cost calculation that used day-ahead sigma metrics, correct?

A Yes. It used day-ahead pricing to -- to evaluate that bill credit.

Q So -- and we can agree that -- you know, I won't attempt to understand the day-ahead sigma, but we can agree it's calculated differently than the administratively determined avoided cost? And when I say calculated differently, I just mean it's a different, I guess, statistical model or -- or some sort of mechanism that's different than the administratively determined avoided cost.

A Mr. Hinton may be able to add to this, but the avoided cost is calculated by running production models and adding capacity, free energy, and deciding what the savings are. The day-ahead pricing, to my knowledge, would be the output of the -- Duke Energy's production modeling that kind of will tell the system what the marginal cost of generation in each hour for the next day is. So they're different, but the avoided cost and the marginal cost are a little related. And I think I'll let Mr. Hinton speak to that.

A (Hinton) Yes. They are related since we're -- the day-ahead is just that, 12 hours, 24 hours ahead of time. Obviously, the avoided cost of energy is looking many years in the future on an 87/60 basis. But also another nuance difference is the -- the daily/hourly rate or lambda. That -- that does not include a capacity payment, whereas avoided cost generally do, you know, with the energy and capacity. So that's a difference that Walmart is taking on that area. There is a -- there is a ratchet inside the mechanism for both DEC and DEP that does raise the avoided energy rate at times when available generation capacity is limited, which acts as a form of a capacity premium, we'll say, but there's not an administratively determined or a preset avoided capacity rate. Again, that's one of the differences between the day-ahead lambdas and the avoided energy cost.

Q Thank you. That's helpful. And -- and this might be -- any of -- any of you can answer this. Can you explain how the Public Staff projects that this solar integration charge will affect those two different avoided cost bill credit caps?

A (Thomas) So the -- the two different bill credits that are contemplated in the -- in the GSA program, which is, I believe -- once again, all of this is subject -- obviously, the SISC has to be approved and the GSA compliance filing also has to be approved by the Commission. So while this is contingent upon timing of all that, but my -- the bill credit, to my understanding, is a reflection of the -- the value to the -- to the system and the credit that that GSA customer would be receiving. But the SISC would really, that would be assessed on the developer, the GSA supplier.

And to the extent that that GSA supplier is an uncontrolled solar facility, they would have to pay that charge. And I would expect that that charge would be reflected in the negotiation between the GSA supplier and the developer -- the GSA supplier and the GSA customer. But, obviously, the implementation of the SISC and the GSA program would be -- would have to be discussed because, I guess, I wouldn't see it as appropriate to both charge the GSA supplier the SISC as an uncontrolled generator and then to also reduce the GSA customer's bill credit by the SISC because, I mean, that would be double recovering the SISC from both the GSA supplier and the GSA customer. So I don't think that's appropriate and, like I said, this is just another detail that would need to be worked out as the GSA program gets implemented and these contracts begin to be negotiated.

Q That's -- thank you. That's very helpful. And I guess -- and, again, I'm asking a question that I don't know the answer to, so bear with me. The administratively determined avoided cost rate, as determined in the order in GSA, your position is that would not include the solar integration charge, assuming that the solar integration charge is accepted?

A Let me just think a little bit about the structure of the GSA program.

MR. DODGE: Madam Chair, I'd like to object to the -- where -- these questions are venturing pretty far from the application of the solar integration charge here in the avoided cost context. I think Mr. Thomas has already asked and answered several questions where he has indicated that that's going to be subject to further review and consideration by the Commission, and some of these variables still have to be evaluated.

MR. SMITH: My response is that it's a 600 MW program. I'm about to talk about a 2,660 MW program of solar that's supposed to come on in the next three and a half, four years. And so to say that it's going to apply to all of that solar and then not have an idea of how it's going to apply, I think that needs to be explored.

CHAIR MITCHELL: I'm going to allow the questions, but Mr. Smith, I ask that you move through this efficiently. And Mr. Thomas, do your best to answer. If you are not in a position to answer, state -- please state so. Thank you.

A So the -- the avoided cost -- the administratively determined avoided cost being paid to the -- to the GSA customer, I hope I'm not restating what

I just said before, but either the avoided cost that's paid to the GSA customer as a bill credit is reduced and that's the end of it, or the GSA supplier, as they receive their -- their payments from Duke, will pay that charge.

So, you know, once again, it's a matter of how you apply it, whether you apply it to the customer or to the supplier, but I think that if you're going to apply it to one, you can't fairly apply it to the other. So you have to -- you have to consider that charge and you have to recover that charge from the QF, but whether you recover from the QF and then you exclude the SISC from the bill credit or whether you include the SISC in the bill credit, but you exclude it from being assessed on the developer, you could do that either way. I know there's a lot of hypotheticals about how that will be implemented. And hopefully as the -- the standard form PPAs take -- of the GSA program kind of take into account the possible ruling in this docket, that that would be, obviously, decided upon and -- between the Utilities and possible customers and suppliers.

Q Thank you, Mr. Thomas. And just so you know, the purpose of the question is that I wanted to get to the point of -- that there was an Order talking about an administratively determined avoided cost, and so me, a lawyer, thinks, okay, there's an administratively determined avoided cost. Does that administratively determined avoided cost, as defined by this Order, include this solar integration charge? And that's the only question I have. I understand your point is that that needs to be sorted out, I think; is that correct?

A Yeah. I think the position we've taken is that the -- the SISC is a decrement to the avoided cost that applies to uncontrolled solar generators, but collecting that is the -- collecting that from the cost causers is the important part, but making sure that's done equitably and fairly and that there's no double charging is also important.

Q Thank you. And without going down this whole path again with the CPRE program, understanding that the CPRE is -- is capped by, I believe, the statutorily defined administratively determined avoided cost, would your answer effectively be the same for that program, that it would have to be determined how it would applied to that program and that it wouldn't just be automatically the solar integration charge goes into that -- that cap?

A Yeah. I think there's probably even more complexities around how it's implemented in the CPRE program because you have the added kind of complication of making sure that the Utility projects and the third-party projects are evaluated on an equal footing, as it relates to the SISC, as both types of facilities are causing the same costs. So, yeah, I think -- my answer would be the same, it needs to be collected, but only collected once, and all projects that are bidding in need to be evaluated fairly, and there's a lot of discussions that still need to happen to ensure that that SISC is -- is considered appropriately in the context of the CPRE.

Q And within the context of CPRE, does the Public Staff have a position as to whether the solar integration charge should apply to Tranche 2 of the CPRE?

A In our -- in some of our filings we've taken the position that we feel that a 20-year contract, as it comes up on the CPRE Tranche 2, is -- it's probably appropriate to consider the SISC on these long-term contracts. And so we've actually advocated in some cases for delay of Tranche 2 to allow this proceeding and the Commission to decide on the SISC. So, yes, we do believe that it is important to consider the SISC in Tranche 2, as it is a significant quantity of solar, and without the charge being assessed on these facilities, it will be ratepayers that will be paying this charge for the next 20 years for that solar volatility.

Q Thank you. And -- and just to make sure I tie this whole thing up, I have two more things. Community solar, also tied to an avoided cost cap. I realize that community solar has not really gotten off the ground yet, but statutorily it's tied to an avoided cost cap. Would your answer would be the same for that -- that program as well?

A Yes, to the extent that those facilities are specific to the community solar program and not rate-based. I believe they are. Yes. My answer would be the same. It has to be considered in terms of that avoided cost cap.

Q And this next question might go to Mr. Hinton, based upon his earlier answer, because one of my colleagues sent me over some language from the recent Duke Energy Progress demand-side management energy efficiency cost recovery ridery (sic) -- cost recovery rider program. And I'm going to -- I'm going to read that now. This is from your colleague, David Williams, and he says, "While the changes" -- and this is from his direct testimony in this year's filing -- "While the changes in program cost effectiveness from last year's to the current year's rider filing are not solely attributable to the changes in avoided cost rates, the impact of the change is significant. As calculated by the Company, these changes decrease the dollar impacts on a net present value basis by approximately 35 percent for avoided energy rates and approximately 15 percent for avoided capacity rates." Is it Public Staff's position that what -- this is apples and oranges, that this is not -- what he's talking about there is not inclusive of a solar integration charge?

A (Hinton) Correct. That would not be inclusive of that rate because those were -- as the rider reflects cost -- avoided cost settings that were done in previous proceedings, not this one.

Q And going into the future, if a solar integration charge is accepted by the Commission, that wouldn't be something -- that would be, within that program, likely excluded as a -- a barometer for avoided cost, correct?

A You're asking me would the SISC charge be associated with DSM and EE programs?

Q Well, when you -- when I look at that testimony, I read it to say that DSM/EE programs are -- are measured against avoided cost. And I'm asking that in the future, if the SISC is accepted, that -- that either will be understood that the avoided cost rate doesn't include the SISC for those purposes or -- or how -- how do you think that will play out?

A Well, with a caveat that this will be looked at again, but I mean, the SISC, it's been testified to, is associated with solar generation plans. DSM and EE programs are generally not -- have that erratic profile. So my expectation, it would not be a part of the avoided cost calculation.

Q Thank you. And that's my expectation as well. And I just -- when they used that avoided cost terminology in the testimony, I just wanted to clarify. Thank you. All right. I'm going to move away. I'm going to talk about the model now.

So we're going to start that the Astrapé model uses 2015 historical data for its analysis, correct?

Q (Thomas) The Astrapé model validated its no solar case against the reserves in 2015, but I believe the Astrapé model is modeling the 2020 system --

A Sure.

Q -- for one year.

A Thank you. And -- and you said the no solar case, so I think the answer to this is yes, but the idea behind using the 2015 historical data was that 2015 was a much lower solar amount in that -- that it provided the knowledge for a no solar scenario, correct?

A Yeah. I think 2015 had relatively -- compared to today, had relatively less solar, and by comparing the no solar results to these results, we were able to see that we're in line with -- with reality.

Q Thank you. And since 2015, North Carolina has added significant amounts of solar to the grid, including in the Duke territories, correct?

A Yes.

Q And as a result, as we've talked about, North Carolina is either number two or number one, depending on what metric, in installed solar in the country, correct?

A I've heard the number two, but number one, California, has got a lot.

Q Yeah. It was something to the effect of PURPA qualified projects --

A Oh.

Q -- so it was earlier in the proceeding. So I had NCSEA's team aggregate some numbers this morning. So subject to check, and understanding that I am willing to file a late-filed exhibit with these numbers, would you agree that in 2016, Duke Energy Carolinas added 433 MW --

total megawatt solar capacity in its North Carolina territory?

A Subject to check. I'm not sure if you're talking about AC or DC, but subject to check, I will accept your number.

Q Yeah. They didn't send me over AC or DC. I apologize. But subject to check, including the South Carolina Duke Energy Carolinas territory, that number for 2016 jumps to 457 MW, approximately, correct?

A Subject to check, sure.

Q And would you agree -- and I'm going to fast-track this, don't worry. And would you agree that, subject to check, in the Duke Energy Progress territories in the Carolinas, Duke Energy Progress added approximately 197 MW capacity of solar in 2016?

A (Metz) Can you clarify? Added on top of what? So you're just looking at the additive amount or are you talking about total case?

Q I'm a lawyer. Additive amount is like wooo, but I'm saying that the -- the installed solar in 2016 totaled 197 meg--- I'm sorry -- solar that was installed in 2017 -- in 2016 was 197 MW.

A And Duke Energy -- are you saying Duke Energy Progress only had approximately a hundred and -- less than 150 MW of solar in its system and Duke Energy Carolinas had north of 400 MW in its system?

Q No. I'm saying installed in that year, in year 2016, so -- so physically installed that year, not -- not including what was before that.

A Subject to check.

Q Okay. Thank you. And that the two -- two totals for, again, installed solar for the year 2016, meaning solar installed in 2016, that number approximately added up to 654 MW for -- of solar capacity for the two Duke territories in 2016?

A I would need to validate these numbers. Going off the back of my head, something just does not seem right in that ratio between DEP, DEC. I mean, they seem flip flopped. I mean, to -- to the extent that you file a late-filed exhibit, I mean, subject to check, but something just doesn't seem right, and I don't think I can go further down this hypothetical.

Q Okay. Well, let's go to here. Let's just move all the way -- subject to check, the aggregate amount of added solar in the years 2016, 2017, and 2018 in Duke territories in the -- in North and South Carolina was 2,001 MW. Subject to check, do you agree with that rough estimate?

A (Thomas) Sure, subject to check.
Q And Mr. Metz, I heard you say something very interesting earlier. You said that in 2015 there potentially could have been significant amounts of solar added late in the year, and that might not -- which is why it might not be reflected in the "no solar" case in the Astrapé study?
A (Metz) That's correct. I didn't understand the context of -- I can't remember the exact number. I believe it was either 100 or 1,000, just trying to put context into what are we talking about, when was the solar added.
Q Sure. And -- and typically -- well, strike that. And that such late additions to the grid might -- might not accurately reflect the exact effect of the large amount of added solar in 2015, given that it was likely brought online late in the year? Is that your point?
A Correct. So, yeah, if you looked at the operation reserves over the year, but yet you add, hypothetically, 90 percent of your total nameplate solar generation into the last two or three weeks of the year, it wouldn't be a correct relationship to say 1,000 MW of solar created this much operating reserves, so I was just

trying to make that distinction.

Q And I think it might go without saying, but I'm going to ask anyway, would you agree that the total amount of added solar from the end of 2015 through 2018 is a considerable addition of solar, compared to the assumption in the Astrapé study?

A (Thomas) I believe that the Astrapé study, the first tranche of solar is well over 3,000 MW, reflective of the system today. If I understand your numbers correctly, you were saying something along 2,000 MW were added in the time period you're discussing. So, I mean, it's -- I wouldn't say that they're -- that --

Q Well, I'm not talking about the simulations. I'm talking about the historical data included in the -- in the model, and that's where I'm going with this. Would you agree that the added solar in those three years would provide historical data related to the cost or benefit associated with the additions of solar to the grid?

A (Metz) So some of the complexities of looking at this, so whether or not you're saying did 1,000 MW in, hypothetically, 2017 added to the grid, and we'll just say -- go further down this hypothetical that they were added at month -- at day one of the year, there's other parameters that you have to take into consideration in looking at the operating reserves, and as for some of the challenges that we took into consideration of -- of how far back or what years do we use in this analysis.

I mean, you have to take in the operation fleet, has it stood its time, what generators were on particular outages. For example, Bad Creek Hydro has been down for significant time periods because they're doing a massive overhaul that would have impacts on operating reserves. You would have to look at what weather phenomenon is taking place. You'd have to take in consideration 2014, 2015 polar vortex, the 2018 cold spell, polar vortex. You'd have to take into consideration the hurricanes, the last three -- the last three major hurricanes that we've had in the last three or four years.

There's a compounding amount of factors of how you're trying to make a correlation tied distinctively between the operating reserves and the benefit or value of solar being introduced to a system, whether or not that's pushing up or down the levels of reserves, contingency, operating, et cetera.

Q Okay.

A I don't -- did that answer your question or --

Q No, but I agree with everything you said. And the reason it didn't answer my question is because I'm talking about validation here. I'm not necessarily talking about simulation, which I -- I think, from my non -- from my attorney point of view, are two slightly different things. And I guess simulation would be something that requires validation, maybe, under most energy modeling. So I guess my question is, wouldn't you agree that it would have made sense for the -- the Astrapé model to validate its simulation runs against those historical years, 2016, 2017, and 2018?

A (Thomas) So the Astrapé model, when it models the 2020 system and it adds solar in a progressive fashion, you're calculating the number of reserves that are required to -- to increment these increasing volatility. I think -- it sounds like what you're suggesting is that Astrapé actually should have created a model that mimicked the 2014 system and then seen how much reserves were quantified and then checked that against 2014 and then did the same for 2015 and 2016 and 2017. And while, perhaps, that would have been a helpful exercise, I think that overall, when you build a model, you use the model as best you can to see if it correctly predicts, with a reasonable degree of accuracy, how the system has performed in the past.

So, you know, using the model at zero solar to calculate the required reserves to maintain this LOLE FLEX metric and then comparing that to 2015, a year with comparably less solar and, presumably, no NERC violations, and finding that you are close to -- reasonably close to the actual performance, you know, that -- that's a type of validation that I think that is common in all sorts of modeling, from energy systems to climate modeling, et cetera. So, you know, building a model that represents each year and validating it is a pretty intensive effort because you have to continually change your inputs and your data sets and the generating units and technologies and fuel forecasts and all those other things.

So I think what they did to validate is certainly a step that put us in, at least, a position to be comfortable with the results. But, you know, no model is going to predict down to the exact MW what the reserves should have been. And like Mr. Metz pointed out, there are many other factors at play here that -- that, you know, you can't always control for. And when you're comparing reserves that are historically held to reserves predicted by the model, the model is -- is operating in a way that is attempting to mimic real-life behavior, but it is not precise. So, you know, even the production cost models that Duke runs on a daily basis that predict marginal cost, that -- it's always going to be slightly different from the actuality, but you've got to look at what are the -- am I close? Is this model accurately predicting the deltas between my cheapest hours and my most expensive hours? That's -- that's really what's important.

Q And I agree. And I guess that's my point. Wouldn't it make more sense to compare the simulation to the actual years of real data? I mean, wouldn't it make more sense to look at the simulation and say here's -- here's it compared to our 2016 volatility issues, here's it comparing it to our 2017, here's it comparing to our 2018?

A Well, Mr. Metz may have something to add, but I -- obviously, the Commission has decided that it has value and has asked for a late-filed exhibit for the reserves in 2014 through 2018. And so it certainly has value, but I think that from our perspective in just ensuring that the model is -- is reasonable, that what we did, looking at that one 2015 year, is -- was appropriate and within the bounds of -- of reasonableness.

Q And I -- and did you all review the Idaho study, the Idaho Power study that was Duke Exhibit -- Cross Exhibit Number 2?

A Yes, I have.

Q And -- and, subject to check, would you agree that the Idaho study used three years of solar data for whenever possible for each of their scenarios to validate their model?

A No. The Idaho study used three years of solar data to predict the volatility of the actual solar output versus a manufactured forecast. So they were looking at forecast error, comparing actual output in 5-minute increments to a -- a manufactured, statistically derived, hourly forecast. And so they used three years of solar data to calculate that. They also used three years of wind data to do the same exercise from different sets of years. They also looked at load data from different sets of years.

So they have mismatches in their data, and they're not validating the model. They're simply looking and saying this is the volatility against this wholly manufactured, persistence forecast that is a statistical forecast to look back and say based on the output of this facility over this last 70 minutes, what would I expect it to be over the next 60 minutes. And then they look at the actual output compared to that manufactured forecast, and that's how they calculate forecast error. And then they throw out certain percent, and that's how they calculate the reserves. So they didn't use three years of data to validate their model. Their model was a production cost model that they ran, and there was no validation against historical data.

Q Thank you. I'm going to move ahead to the -- a portion of the Astrapé model that talks about -- the Astrapé model projects high numbers of solar penetration in one of their runs. It's existing transition -- existing, plus transition, plus 1,500 MW in each of the territories; is that correct?

A It's existing, plus transition, plus Tranche 1, plus 1,500 MW, yes.

Q Okay. So CPRE Tranche 1 was included in there. Okay. Thank you. So I guess my question is -- actually, I'll strike that. Was there also a -- a run with a -- and please correct me if I'm characterizing this wrong; this is, again, a lawyer trying to speak engineer -- but they have a run that's a 75 percent volatility, 1,500 MW addition as one of their simulated runs?

A Yes. And let me elaborate a little bit on that. To my -- my understanding of the Astrapé model is that they -- for the existing plus transition, they use solar volatility data for one year to estimate the volatility of kind of the existing solar fleet so there was very little extrapolation made there. But when you're looking at adding, you know, over 2,000 MW with Tranche 1 and 1,500 additional megawatts in each balancing authority, you know, you can either use the existing solar fleet's volatility, which is what they did in one model run, they said adding all additional solar will have no additional diversity benefits, absent what we already have on the grid. And I think they supported that analysis in a way.

But then they also said, listen, if we add that much solar, 1,500 additional MW, what's expected, it will reduce the volatility at some part. Clouds are finite, these farms are huge, spread out all across the state, that's a lot of MW, but let's assume that our volatility will be reduced by 25 percent, and then they ran the model there. And you can argue about whether a 25 percent reduction of volatility is the right number. There's been significant arguments about that, but to me, it's almost, to a certain extent, irrelevant because the plus 1,500 MW was purely an exercise to show what could happen based upon volatility and diversity benefits. It's not being used to establish any charge. It's not being used to set rates or caps, so it was almost purely an academic exercise, so...

Q And that -- and that might be true and it might be academic to you, but do you understand that the solar developers look at this when they do their financial analysis and determine whether or not they can participate in programs? I mean, is that -- did you all talk about that when you discussed the -- the model?

A I would imagine. I'm not a solar developer, but I would imagine that the QF would look at the proposed charge and the proposed cap. I don't know why the plus 1,500 MW charge would -- would reflect in their -- their analysis. Mr. Metz may --

Q Thanks.

A (Metz) So --

Q Oh, go ahead.

A But early on to the process we saw, sort of, the upper bound, if you would, or with the -- the entire hypothetical. And if you looked at the cost curve, it's into the exponential curve. I mean, that was one of the components for -- in working with the Utilities of pushing towards a cap to say, hey, this can't go boundless, understanding there could be challenges into the upper ends of the exponential curve. So we thought it was reasonable to provide at least some price certainty with taking in the constraints that we discussed here thoroughly and -- and implement the cost cap.

Q Thank you. Okay. So moving along here, I want to talk about the language and the constraints of the respective models and studies you've talked about in this case. And I'm going to page 53 of the Astrapé study.

A (Thomas) Okay. I'm there.

Q And -- and this is -- this is the quote that I want to focus on. It's near the end there. "While the study contemplated bookend intra-hour volatility distributions using the base case volatility distribution and 75 percent of the base case, which assumes additional diversity, additional data over the coming years should be used to update these distributions and better project the ancillary service cost impact of higher solar penetrations." And my question is, what exactly does this mean to you in terms of the -- of the base case? Does Astrapé project changing the base case at any point in future years?

A So I think what this statement is getting across -- so first off, the base case has no solar, so it's not using solar data. It doesn't anticipate volatility from solar. But in the -- the change cases, when you start to add solar, you know, having more solar data as -- as the fleet that's connected to the Duke grid expands, Duke will get more data from all these facilities. There will be more facilities providing data spread over a larger geographic area, and Duke may find in the next filing in two years that, hey, the diversity benefits of all this spread out solar is greater than we imagined and, in fact, more solar is actually reducing the volatility of the fleet as a whole, and that reduces integration cost.

And I think, you know, Witness Beach in his direct testimony provided direct evidence of that with two studies that were studied over time, and as more of intermittent renewable generation was connected to the grid, the study found that their integration cost actually did decrease. And part of that may have been because of the Utility may have been trying to estimate volatility for additional tranches of solar, but in reality, once they acquired more data, they were able to say, well, our estimates may have been wrong and we're going to revise those. And I think that's part of the reason why we do support the refresh is because the additional data that can be input into the model to project volatility is only going to improve over time.

Q I'm going to get back to my line of questioning and I'm going to reach back for this one, but you just made a really good point. Wouldn't the 2016, 2017, and 2018 real data that Duke has being imported into the Astrapé model improve the accuracy of this model?

A So I think they used one year of solar data, and remember that this -- this model was, I believe, subject to check, run in 2018. So, I mean, they only had a limited number of data to choose from when they're talking about modeling this volatility. You go too far back and -- and your solar fleet has shrunk and so the data you're selecting is -- is not enough. And if you -- so I believe that they took the most recent data, subject to -- I'd have to check, but I think that solar volatility data was from either 2016 or 2017 as they were going into the study.

But, you know, when they -- when they do the study in 20--- for the 2020 filing, I would expect that they'd be pulling solar volatility data from 2019, and so it's going to be a larger fleet and it's going to reflect those benefits of diversity and see if they actually materialize. So, you know, I think we had raised some concerns in our comments about the solar volatility data that was being used and the one-minute -- or the one-year window in which it was being selected, but just upon kind of discussions with the Utility and talking amongst the Public Staff's task force investigating this, you know, we determined that, you know, in the future tranches will provide more accurate data, and you really -- you have to be -- you have to narrowly -- you have to select the best data that you have available at the time that you do the study.

Q And just one follow up on that and then I'm going to get back to the base case line of questioning. In the refresh, would you expect or would the Public Staff expect that Duke will provide -- assuming the integration charge is accepted by the Commission, would the Public Staff expect that Duke will validate its real solar data against the continuing projections in the model at that point?

A Yeah. I think in future filings when this is filed, the Public Staff and Intervenors as well will probe the model and see what improvements have been made and what changes have been made, and especially in light of some of the testimony in this proceeding, I would expect that Duke would perhaps put more emphasis on -- on validating their findings with -- with historical operations. So, yeah, all -- of course, we're going to review this SISC calculation and quantification in the next filing just the same that we've done in this one.

Q All right. My next question relates to the base case. And going back to what we were talking about, I read the -- the Astrapé study to say that they will not change the base case going forward, that they'll change the other data. Is that consistent with how you read it?

A I think the base -- my understanding is the base case will always include zero solar, as you attempt to quantify the charge of the fleet that's currently added, but the base case -- my understanding is that the base case will change to reflect the fleet of the -- that's being studied. So if units have retired between the studies, they'll be removed from the fleet. If units have been added, they will be added to the fleet. And, you know, to the extent that that makes the fleet more flexible and reduces the charge, then great. So it's really -- you know, the study being updated is not going to keep the same static base case in terms of the system characteristics.

Q Thank you. That helps. And so just to put a bow on that, so if the generation mix -- if any other technologies emerge, you know, assuming the no solar part of it, the base case can and will change to reflect those changes that you just referred to?

A Yeah. That's my expectation, yes.

Q Good. I'm going to fast forward through a few questions. So I'm going to talk about some language from the Stipulation, and this is -- I think it's on page 5. Hold on one second. This is -- this is talking about the biennial refresh, and so if you can forward to that section. I apologize. I didn't put the page number down. That's my mistake. And I'm going to read this portion of the Stipulation under the biennial refresh section. "The Stipulating" --

A Page 7 --

Q Oh, go ahead.

A Page 7, I believe, it starts.

Q Oh. Thank you very much, Mr. Thomas. Reading that, "The Stipulating Parties agree that it is reasonable and appropriate for Duke to biennially review and update the Companies' average and incremental ancillary services cost. The Integration Services Charge should be adjusted in future biennial avoided cost proceedings to accurately reflect changes to DEC and

DEP's average ancillary services cost as incremental solar is installed on the DEC and DEP systems." Subsection B, "The Integration Services Charges approved in this proceeding should continue in effect until the date that the Companies file updated solar ancillary services studies and/or analyses in the next biennial avoided cost proceeding that quantify DEC's and DEP's average and incremental cost of solar integration. The new Integration Services Charge would then become effective subject to true-up, if required, after a final Commission order on the" -- Commission -- "on the "Companies'" -- excuse me -- "biennial avoided cost filings, similar to the availability of the Companies' standard offer and variable rates."

I read that to say that it is appropriate for Duke to review every two years the ancillary costs on their system and then in -- update that data to the model; is that correct?

A Well, the model outputs the ancillary services costs. My understanding of this is that the ancillary services cost will be updated by rerunning that model, reflecting the addition of incremental solar and -- as well as the changes to the generation fleet that I've already discussed.

Q But it assumes that the model will stay the same, correct?
A I think it -- the Stipulation doesn't specifically specify a model that's being used for this update, but just a -- a methodology in trying to quantify these -- these charges.
Q But can you understand the concern of -- of NCSEA and some of the other Intervenors that -- that there's no carve-out here allowing for a new model, new validations, new assumptions, or updating the other -- otherwise, updating the model?
A Well, I wouldn't agree with that characterization. Looking at the last sentence of Section B, you know, it -- the new integration services charge would be effective, subject to true-up, after a final Commission Order. So, I mean, I think that if -- in the next avoided cost filing if certain inputs to the model are challenged or if an Intervenor presents a better model that the Commission finds to be more reasonable in quantifying those costs, I think it's well within the Commission's power to direct Duke to change their cost to -- to reflect the findings of a new model. So I think that the -- the Commission Order language that is in here allows for any changes that are approved by

the Commission and deemed reasonable by the Commission to be implemented in assessing that updated charge.

Q Thank you. So it would be -- and would you characterize the Public Staff's position that new analyses, processes, inputs, assumptions, et cetera, would be available for analysis and potential change in future biennial reviews?

A (Metz) The Utility is still going to have the burden of proof to present this Commission of whether or not it's appropriate or not. This Stipulation does not preclude that.

Q I wasn't talking about burden of proof. I understand the burden of proof the Utility has. I'm actually asking about whether the Stipulation, as you all understand it, allows for the Public Staff and Intervenors to modify or otherwise change the model, the underlying model that's at issue here, in order to more accurately reflect, from whoever's perspective, what they think the model should be?

A (Thomas) Yeah. Nothing in the Stipulation, to my knowledge, prevents Intervenors, Public Staff, from conducting discovery and -- and providing expert testimony and questioning the results of the model in future years, so I don't see anything in the Stipulation that would prevent the same type of review on future studies, as we've seen in this proceeding.

Q Would the Public Staff oppose a collaborative stakeholder process to produce a new model in -- before the next biennial refresh, assuming this charge was accepted?

A (Metz) I want to say not necessarily opposed from a comparative. I can't go on a limb to say that -- that it will be adopted, but to the extent where someone wanted to develop a different methodology and compare it, I mean, it's no different than the case here where we're comparing the Idaho study to the Astrapé study. I mean, to the -- to that extent.

Q Well, and -- and just to be clear, the difference here is that there's a Stipulation here that the Public Staff and Duke agreed to that the Intervenors were not directly involved with, and that -- and that's the difference, I think.

A The Stipulation is between Duke and the Public Staff, yes.

A (Thomas) And I would just add to that, that, you know, as I'm sure -- I think you may be alluding to the Idaho study -- the 2016 Idaho study is a reprise of a 2014 study after the Commission determined that that study needed improvement and a collaborative process. And to the extent that the Commission looks at this study and decides that a collaborative process would be helpful in developing future charges, of course, the Public Staff would support such a proceeding.

Q Thank you.

MR. SMITH: Nothing further.

CHAIR MITCHELL: We're going to take a break and return at 11:15. Let's go off the record.

(Recess taken from 10:59 a.m. to 11:17 a.m.)

CHAIR MITCHELL: Let's go back on the record, please.

CROSS EXAMINATION BY MS. ROSS:

Q My name is Deborah Ross, and I represent the NC Small Hydro Group. And Mr. Hinton, we're going to get to hear from you now. You've been very patient all morning. I know you were waiting to have somebody ask you a series of questions. So in your testimony on pages 10 and 11, you say that while many QFs will seek to renew their PPAs at the end of their term, you don't think that Duke should assume that capacity and energy from existing QFs will be available if they -- if they renew their contracts; is that correct?

A (Hinton) For purposes of determining that statement --

COMMISSIONER GRAY: Pull the microphone up, please.

THE WITNESS: Yeah.

A For purposes of determining a need, they should not assume that existing QFs will -- will automatically renew their contract.

Q But you recognize that existing QFs have a right to renew their contract under PURPA?

A Correct.

Q And you also acknowledge that most QFs will seek to renew their contracts under PURPA, correct?

A I think they will make a business decision based on expected capital expenditures going forward, and they'll decide whether it's worthwhile to renew their contract.

Q And you also recognize that several QFs have been contributing to winter peak over -- over the periods of their PPAs, correct?

A Yes. Hydroelectric facilities, undoubtedly, have done that, and solar, to a small extent, when the peak or hours of high load extend when the sun is shining, but as -- those are few and far between.

Q Right. But there have been QFs, hydro and others, too, maybe biomass, landfill gas, whatever, that have been contributing to -- to the needs for capacity during their PPAs?

A Correct.

Q Thank you. And most of the small hydro QFs in the state have been around since the 1980s and even before the Legislature enacted Senate Bill 3; is that correct?

A Yes.

Q Okay. And the vast majority of hydro QFs have renewed their PPAs; isn't that correct?

A We've got some data responses, and my recollection is that is correct.

Q Okay. Thank you. And then in Duke's CPRE program that they have right now, that CPRE program is only available for QFs that are placed in service after the date of the initial competitive procurement; isn't that correct?

A I believe that's correct, subject to check.

Q So CPRE is only available to brand new QFs, not contract renewals; is that correct?

A Yes.

Q Okay. Thank you very much. And so that would mean that existing QFs don't have as many alternatives as new QFs for entering into contracts with the Utilities. Existing QFs wouldn't be able to take advantage of the CPRE program, for example?

A With respect to CPRE, you're correct.

Q Right. New QFs would be able to just exercise their PURPA rights or participate in CPRE. They have a variety of ways to operate, correct?

A I believe so, yes.

Q Yes. Thank you. And -- and as we've just talked about, existing QFs are already providing capacity during winter peaks. Hydro QFs are doing that in particular?

A There are a limited number of QFs that do provide capacity or energy at time of the peak.

Q Okay. Thank you. And then the FERC has ruled that -- and we hear about this a lot from the Utilities -- that there's no obligation under PURPA to pay for -- for a Utility to pay for capacity that would displace its existing capacity arrangements; is that correct? So if they already have the capacity, they don't have to pay for more?

A As I understand it, that is correct.

Q Okay. Thank you. And then PURPA excuses capacity payments only in situations of excess capacity over the planning horizon; isn't that correct?

A Without looking at PURPA recently, I will assume that is correct.

Q Okay. I -- thank you. And, actually, I have some testimony that you've provided before where you've said exactly that.

A Yeah.

Q So if you didn't agree with me, I would have shared that with you. And then are you aware that in Idaho -- and we've been talking about Idaho for like -- for the whole week; it's great -- but the Idaho Utilities Commission has repeatedly held that it's logical if a QF has been paid for capacity at the end of its contract term and the parties are seeking to renew or extend the contract, that the renewal or extension would include immediate payment of capacity because an existing QF's capacity would have already been included in the utility's load and resource balance? Are you familiar with what the Idaho Utilities Commission has done?

A To be honest with you, with that language, I am not.

Q Uh-huh. Okay.

A I'll accept it, subject to check.

Q Okay. Well, thank you. It -- it does come directly from a commission Order in Idaho. It was provided in the Hydro Group's initial statement. So thank you.

MS. ROSS: Those are all my questions. Thank you very much.

CHAIR MITCHELL: Questions by any remaining Intervenors?

(No response.)

CHAIR MITCHELL: Duke?

CROSS EXAMINATION BY MR. BREITSCHWERDT:

Q Good afternoon, gentlemen. Brett Breitschwerdt on behalf of Duke Energy. How are you? I guess we're not to afternoon quite yet. I just have a few questions for Mr. Metz. Mr. Thomas has largely answered all the questions that I had, so thank you for that.

First, Mr. Metz, if you could turn to page 8 of your testimony, please.

COMMISSIONER GRAY: Pull your mic up.

MR. BREITSCHWERDT: Still? I'm going to get this.

A (Metz) Page 8?

Q Yeah. So starting on page 7 and then on to page 8 you talk about the issue of overpaneling. Is that -- additional energy and repaneling of facilities or

overpaneling facilities. Do you see that?
A Yes, I do.
Q And you generally say that repaneling or overpaneling can have the effect of increasing the energy output without necessarily increasing the contract capacity or the capacity of the facility. Is that a fair characterization?
A That is a fair characterization, yes.
Q And then at the bottom of page 8, lines 10 through 12, you make the statement that overpaneling can have a material impact on the facility's production profile and total energy produced. Do you agree with that?
A Yes, I do. And I believe Figure 1 illustrates that point.
Q I agree with that. So if you'd jump over, please, to your testimony on page 10 going on to 11, top of 11 you make the statement that -- and you're speaking back to the material alteration definition that your testimony presents on page 10 -- that it appears under this language that overpaneling or repaneling would not likely be considered a material alteration, so long as the existing capacity is not increased, and a decrease in existing capacity would only be considered material

modification if it decreased by more than five percent. Did I read that correctly?

A Just made a change. Material modification should be material alteration in the beginning of this hearing. That was a typo on my part, but in the beginning.

Q That's right. Thank you. I missed that. So with that change, I want to be clear that your testimony is not -- that based on the existing Power Purchase Agreement that exists today or the material alteration definition that Duke Energy has proposed, that a QF can overpanel its facility in such a way that it materially increases the output of the energy during a given year. So I want to point you specifically to -- on the definition of material alteration where it says that the estimated -- and this is on line 20 -- the estimated annual energy production facility, that's included within the definition of existing capacity.

So I'll reframe the question with that long-winded explanation. So based on the definition of existing capacity, which includes the energy produced during the year, is it your testimony on page 11 that overpaneling that exceeds what the QF's annual energy production was contemplated to be under the PPA or when the facility was originally designed, would be a material alteration, and that would require the Utilities' consent?

A Yes, by the terminology used in material alteration, if you increased, as like the Figure 1 illustrates, then it would a material alteration.

Q Okay. Thank you. And so -- and just -- you had some questions from Ms. Bowen about the definition of material alteration and the process through this proceeding where the Company initially filed a proposed material modification definition, and then based on feedback from NCSEA and the Public Staff, materially altered that definition, modified it, revised it to reflect what's here listed on your page 10; is that accurate?

A That's accurate, yes.

Q And so on page 10, line 15 to 16, it says that when the Company is evaluating a proposal of a material alteration to the facility, they'll do so in a commercially reasonable manner. Do you agree with that?

A Correct.

Q And so it also in the definition speaks to the fact that at the recommendation of Public Staff and other parties, the Company clearly prescribed, and this is starting on line 23 to 28, that normal replacements or repair of equipment, solar panels, et cetera, with like-kind equipment during the normal course of business would not be a material alteration. Is that the Public Staff's understanding of --

A Yes. I believe --

Q -- what the definition says?

A Yes. I believe that -- and Duke took into consideration the conversation we had with them, as well as Intervenors' input, on allowing for a degree of life-cycle management for the QF facility and no need to go further down back through NCIP and levels of revisions.

Q Right. So even -- so with that new definition and the conversation you had with Ms. Bowen earlier about the fact that in the contract capacity section it says that Duke has its sole discretion to make that determination, it's still subject to being a commercially reasonable determination and expressly allows the QF to make those normal life cycle changes to its facility that we just talked through; is that correct? Is that your understanding?

A Yeah. I'm not a lawyer, but, yeah, as we used the definition in the -- later into the contract of how she defined, when you go back to the definition, it does say commercially reasonable manner.

Q Okay. Thank you. All right. I'd like to turn to -- and just maybe big picture here. Your testimony supports the Public Staff's position that a QF that proposes to add battery storage, the Public Staff thinks it would be in, just to keep it simple, the public interest to do so, as long as the new output -- the additional energy output, as you've defined that term, would be at the most current avoided cost rates. Do you agree with that?

A I agree. That's correct.

Q Okay. And on page 6 of your testimony, starting on line 1 through 8, you generally speak to the fact that the Public Staff agrees that it wouldn't be appropriate to allow this additional energy to be sold at the prior avoided cost schedules and rates that are preexisting because, as you state on lines 4 through 8, paying QFs for additional energy at old avoided cost rates will be unfair to ratepayers as they, being the ratepayer, would no longer be indifferent between energy supplied by a QF energy generated by the Utility. And that's generally the position that the Duke Utilities have taken for the full facility; is that correct?

A That's a fair characterization, yes.

Q Okay. And so I want to explore this concept of additional energy just a little bit. I think one key consideration is, would you agree with me that both energy and capacity are paid in North Carolina based on an energy basis, meaning the capacity value of the QF is paid during on-peak hours to keep a similar -- simpler premium in on-peak hours under the new rate design and energy only is paid under the old off-peak hours?

A Yes. That is correct.

Q Okay. And so in terms of the value that a QF is delivering to the system in terms of capacity, if you have a facility that is a 5-MW QF and they're proposing to add 2 MW of battery, let's say, and they are going to sell the output of that QF under your alternative energy proposal, so the original QF continues to deliver its full output under preexisting rates and the battery storage delivers its new output under the new rate design, would you agree with me that there is the potential for the QF to be paid for more capacity value than it's actually delivering to the system?

A So if I'm understanding the hypothetical, and let's use maybe the terminology of price arbitrage, to the extent where you say you had a -- I believe you said 5-MW facility and 2-MW battery, if under the 5-MW facility, let's say Sub 136 vintage rates, and they're being paid on a levelized amount of its production profile, and then any excess energy or additional energy, as I define in my testimony, as being paid at the new Sub 158 rates, to the extent if -- from a price arbitrage perspective, if you were to pull away the output energy from the 5-MW facility at its time of contribution -- so I'm not talking about the excess. The excess should go into the battery and be discharged at new rates. Well, let's say the part below the excess, if you pull away from that component, then, yes, there is the potential for a, lack of a better word, double-dipping or dual capacity component because both the Sub 158 rates will have a capacity component and the Sub 136 vintage would have a capacity component. There has -- we have to work through the nuances to ensure that the capacity being paid over in this system is not being paid again over in this system.

Q And isn't it true that under the -- let's say the Sub 136 rates or even the Sub 140 rates, the vast majority of the capacity value is paid in summer afternoons?

A That's correct.

Q And in this updated Sub 158 rate design, the premium peak hours and the peak hours are focused on winter capacity in the early mornings when Duke has the highest loss of load risk going forward?

A That's correct.

Q I didn't know if Mr. Hinton wanted to speak to that.

A (Hinton) I'm agreeing with you.

Q Very good. So the implication being that this qualifying facility, that delivering capacity, the full capacity value or the -- the bulk of the capacity value in the old rates in the summer would also be getting paid for delivering effectively the same capacity value under the updated rates through the injection of storage output into the system in the winter; is that accurate?

A (Metz) Could you restate that one more time, please?

Q Sure. I think it's just drilling down on the same question to make the point that because of the change in rate design, there is the result of, I think you used the term double-dipping, or under this new concept of alternative energy, it's an issue that we need to think through to make sure the QF is not being paid twice for delivering the same capacity, based on the way the old rates were designed versus the way the updated, more granular rates that are proposed in this proceeding are designed.

A That's correct. And that was the intent of the -- the dedicated sort of stakeholder group to work through these minor nuances, the possibilities they can exist.

Q Yeah. And so in addition to the technical issues, which you lay out extensively in your testimony, rate issues would also be a consideration to make sure that there's not an excessive payment to the QF under the proposed alternative energy concept that the Public Staff has laid out?

A Correct, because I believe I used -- there's the technical matters, there's the commercial terms and agreement matters, and there's also regulatory challenges, sort of this minor topic, although it's important. Sort of follows in around both the regulatory and -- as well as the commercial term.

Q Okay. And have you had an opportunity to review Duke Energy's supplemental rebuttal testimony that was filed last Thursday?

A Yes, I have.

Q Okay. Do you have a copy of it with you, by chance? I can provide a copy.

A If you can provide a copy.
Q Yeah.
A Or Mr. Thomas has one.
Q Okay. Very good. So if you could turn to page 13. I just want to get the Public Staff's perspective on Duke Energy's position here. So I think in -- I'll characterize this, but in pages 1 through 12, Duke Energy generally reaffirms the initial position the Company took in its initial comments that Duke Energy believes it's most appropriate to pay a QF that materially alters its facility and proposes to add storage at the most current avoided cost rates. But on page 13, there's a question and answer where -- and this is long-winded, but I think it would be more efficient for me to read it to you and then allow you to respond -- where the Company says if the Commission decides to -- or let me start with the question.
So if -- if the Commission -- well, "Mr. Snider, does Duke have any specific recommendations for the additional consideration or benefit to consumers that would be appropriate if a QF seeks the Utility's consent to modify its committed QF PPA and to obligate customers to purchase additional energy from the already committed QF proposed and add storage?" And then I'll paraphrase

the answer down at the end, but essentially, Duke's position is if the Commission decides to further investigate this complex issue, such as through the working group the Public Staff has recommended, Duke's position, there should be some quantification and appropriate consideration of benefits to customers that result in the additional cost being imposed upon them by the new storage being added and the original QF being able to sell at the old avoided cost rates.

And the Company's statement says "The Commission should provide clear guidance that any proposal to modify a committed QF during the term of an existing legally binding commitment or PPA should be evaluated by Duke and the Public Staff through the lens of ensuring that customers benefit from the incremental QF investment."

Does the Public Staff agree that there should be some incremental benefit to customers of a QF that's proposing to make an additional investment to add storage that's already committed to sell from its additional facility, and is that something that the Public Staff will consider through a working group, as you proposed?

A I believe it's a valid input as the stakeholders presenting to the group, it should be at least brought to the table and discussed. So, yes, it would be taken under consideration.

Q And the Duke testimony goes on to provide some examples, such as storage protocols, discussion of the ancillary services charge that is not being included for existing QFs that have established a legally enforceable obligation prior to this proceeding, or enhanced dispatchability of QFs that are -- traditional QFs in our limited system emergency. Do you think those are considerations that the Public Staff would be interested in discussing as part of that proceeding?

A Absolutely.

Q Or strike the proceeding, but as part of the working group?

A Correct.

Q We don't need an additional proceeding. That's all.

MR. BREITSCHWERDT: I think Ms. Fentress has some questions for Mr. Hinton.

MS. FENTRESS: Thank you.

CROSS EXAMINATION BY MS. FENTRESS:

Q How are you, Mr. Hinton?

A (Hinton) Doing well. Thank you.

Q Good. Good. Mr. Hinton, I'd first like to start with your testimony on page 13, lines 11 through 18.

A You said page 13, lines 11 through 18?

Q Yes.

A Okay. I'm there.

Q Would you agree there that you have asked for the Utility to clarify when a renewing or an existing QF should establish a new LEO, both for calculating avoided cost rates and determining when the facility will be eligible to receive a capacity payment?

A Yes. That's what my testimony reads.

Q And have you had -- have you reviewed Witness Johnson's testimony -- Duke Witness Johnson's testimony on this issue?

A Yes.

Q And do you agree that he indicates that a standard offer QF can commit for the Commission approved biennial rates in effect at the time that that existing standard offer PPA expires?

A He says within one year, if I recall, correct?

Q Well, for standard offer he indicates that when the PPA expires, that if they seek to reenter a new standard offer PPA, that they would be eligible for the biennial rates in effect at that time. Do you agree with that?

A Yes.

Q And, now, for negotiated QF contracts, he indicated that they could negoti--- a QF could commit a year ahead. Do you -- do you see that testimony?

A Yes.

Q And that they then had six months under the Notice of Commitment form to execute a new PPA?

A I think he says just that, yes.

Q And I believe your recommendation was that the Utilities established that so that they could meet a couple of criteria that you identified. The first was that the period of time for establishing a new LEO should be long enough to allow the QF to have sufficient information regarding the rates for that -- that they may be eligible for; is that correct?

A That's what I say there, yes.

Q And do you agree that -- I'm sorry, back up just a little bit. And then you also -- that's on the one hand. On the other hand, you indicated that the period of time for establishing a new QF should not be so long that it -- that the rates would be -- the avoided cost rates would be misaligned?

A Right. And, again, we're talking about, at this point, renewals for existings, correct?

Q Yes. Existing QFs that are seeking to enter into new PPAs when they --

A Under the standard contract.

Q -- would establish a LEO, yes.

A Right.

Q Yes.

A Yeah. We believe a reasonable time period should be a year for renewals. And standards could -- could actually go to possibly two years, but most likely less than two years, but with the thought that we just want to keep the current avoided cost in alignment with the standard rates offered to the QF.

Q Exactly. And do you believe that Mr. Johnson's recommendation strikes that balance that you were looking for in your testimony?

A Yes. Within, like I said, one to two years for standard offers would -- may ensure that there wouldn't be a stale rate involved.

Q Right. But for negotiated QFs, a LEO established a year before it expires and then...

A Well, a negotiated QF that wasn't making a change to its structure, its generation facilities, that would sound logical, to do it at the year. However, if there was a -- batteries being added to the unit, it could take easily a longer amount of time to go through those negotiations. I mean, the track record for years for old cases when there was renewal when the actual generation unit was changed, it can take several years for those negotiations to come up with a reasonable agreement. So -- so one to two years for negotiations, assuming they change the structure, like adding the battery storage would be an example.

Q Would that be because adding battery storage could adversely impact customers by exposing them to overpayments?

A That could also be from the fact that -- that the Company's evaluation of the benefits of batteries don't coincide with the developers.

Q Okay. Okay. Thank you. I have just a couple other questions. Ms. Ross asked you some questions about a decision in Idaho regarding capacity payments. Do you recall that line of questioning?

A Yes.

Q Okay.

MS. FENTRESS: May I approach?

Q I'm going to show you an exhibit that was introduced and moved into evidence yesterday. I believe it's DEC/DEP Johnson Cross Examination Exhibit 1. Mr. Hinton, will you agree with me that that cross examination exhibit shows General Statute 62-156, as amended by recent legislation that has been ratified, but not yet signed by the Governor?

A Subject to check.

Q Okay.

A Yes.

Q And I'm happy to show you the old -- or the existing 62-156, but I thought since that had already been moved into evidence, this might be quicker.

A Yes. Go ahead.

Q And would you agree with me that that statute says -- I'm sorry -- that Section 3 says that the rates to be paid by electric public utilities for capacity purchased from a small power producer shall be established with consideration of the reliability and availability of the power?

A Yes.

Q And then it further was -- would you agree with me that House Bill 589 amended that statute to provide that a future capacity need shall only be avoided in a year where the Utility's most recent biennial integrated resource plan filed with the Commission, pursuant to

General Statute 62-110.1(c) has identified a projected capacity need?

A Yes. That -- that's the process we've operated under. Correct.

Q And would you agree -- if you look down at the -- at the bottom of that statute, there is -- there is some highlighted language, and it refers to the limitations on capacity payments shown in Subsection (3) -- 62-156, Subsection (3)?

A Yes.

Q Are you aware if the state of Idaho has a similar limitation on capacity payments that is provided for in a statute?

A I can't attest to that. I'm not sure of that.

Q Would you agree that such a statute as 62-156 would be something a Commission would need to consider if they were setting avoided capacity rates?

A Without a doubt. It's important that if -- that these rules we've got on the books now, they only allow a capacity payment to be made when capacity is needed is -- is an important criteria in designing the appropriate rule to make.

Q Thank you, Mr. Hinton.

MS. FENTRESS Nothing further.

CHAIR MITCHELL: Dominion?

CROSS EXAMINATION BY MR. DANTONIO:

Q Good late morning, gentlemen. I hope you all are doing well. Nick Dantonio on behalf of Dominion Energy. Mr. Thomas, I just have one question for you so we can get something on the record here. In your summary, you note that your testimony addresses Dominion's in-principal agreement with the Public Staff on rate design, correct?

A (Thomas) That's correct.

Q And have you reviewed Mr. Petrie's rebuttal testimony filed in this proceeding?

A Are you specifically referring to the -- where he proposes the rates and schedules?

Q Perfect. We can skip a few questions. Yes, at the end there where he proposes -- he sets forth the Company's currently proposed energy and capacity rate design?

A Yes. And that's the in-principal agreement that -- that I'm referring to.

Q Perfect.

MR. DANTONIO: No further questions. Thanks.

CHAIR MITCHELL: Redirect?

REDIRECT EXAMINATION BY MS. CUMMINGS:

Q Mr. Thomas, yesterday you were asked by Mr. Levitas about the integration charge Stipulation and about the cap that's proposed in that Stipulation. Mr. Levitas specifically asked you about whether the cap was based in reality. Would you agree with that characterization, and can you explain a little further how the Public Staff arrived at that cap?

A Sure. So as I alluded to a little bit yesterday, that we do believe the cap was based in reality, so I would disagree with Mr. Levitas' characterization. To just reiterate, we looked at what the applicable charge would be for that cohort, that vintage of solar connecting to the grid, and decided to impose a cap that would attempt to balance the risk of ratepayers subsidizing this -- or bearing the burden of cost above the cap, while also protecting the rights of QFs to some revenue certainty.

And part of the reason we entertained the idea of a cap is, you know, in the Sub 148 Order, the Commission expressed the -- when considering the energy rate refresh, considered that the concept of a collar or a band deserved further scrutiny and appeared open to the concept of this kind of a cap or a band. So it wasn't a concept that was completely foreign to the Commission's consideration, and so by -- by attempting to quantify the amount of solar that would be connected and, you know, using the guidance of the 148 Order, we felt that the cap was based in reality and appropriate.

Q Thank you. And further on that Stipulation, Mr. Levitas mentioned the off ramp for controlled solar, that it could have the ability to reduce or eliminate the integration charge. But he was concerned about timing and asked you if you -- and I would like to ask you if you are also concerned about the timing of guidelines for solar QFs to -- to be able to comply with any guidelines that may come out?

A Yes. I'd say that the Public Staff is a bit concerned with the timing. We think it's important to provide QFs that -- solar QFs that can operate as a controlled generator to avoid that charge, but to Mr. Levitas' point, the timing of all of this is rapid, and we have not yet seen an energy storage protocol that -- that would provide that off ramp, but -- I think I may have talked a little bit about this yesterday, but if not, the CPRE Tranche 2, the Commission has required Duke to hold meetings with market participants to look at the energy storage protocol to be used in future tranches. And I think that whether voluntarily or directed by the

Commission, that would be an excellent venue to also discuss what an energy storage protocol might look like that would provide that off ramp, while still providing the QF with some flexibility and freedom to utilize the excess capacity of the battery to shift energy from -- from off to on peak. So, certainly, it's going to take some time to -- to hammer this out, but I think that there may exist a venue that's already discussing this, and hopefully it can be designed and released soon. Obviously, the sooner, the better.

Q Thank you. That's helpful. And today Mr. Smith asked you about the GSA program. As far as the -- the GSA is -- is still being developed, and they're still -- we're still waiting on a final order, can you speak to whether or not, when the GSA program was proposed and when there was an oral argument here before the Commission on what the bill credit should be, was the integration charge at that point being proposed or...

A I -- I don't believe so. And it's been -- the GSA has been -- it's been a while, but I don't believe that the integration charge was -- was considered in the oral arguments for the GSA.

Q And do you believe that the Public Staff and all the Intervenors and the Utility would benefit from --

from more discussion on how to implement this in the GSA context?

A Yes, I believe so. Yes.

Q Thank you. So Mr. Smith also asked you about the integration services Stipulation and the participation of the parties involved. And over the course of the nine months that you were involved in this proceeding and the many comments and reply comments and discussions, did the Public Staff and other Intervenors have conversations, and did you take into consideration their input in this proceeding?

A We certainly took into consideration their input, and we did reach out to the Intervenors to attempt to clarify our concerns and get their -- a better understanding of -- of where they were coming from.

Q And you were asked if, going forward, in a future avoided cost proceeding, if you would support a collaborative process to come up with inputs or different analysis or different models. Can you speak to the Idaho technical review group and what that process involved and what the Public Staff would support similar to that?

A Sure. So I'd like to just preface this by saying that the Public Staff supports and stands by the Stipulation on the SISC charge filed in this proceeding, but were the Commission to determine that a review group -- a technical review group similar to what was taken in Idaho would be appropriate, I think we would support that, but I think it's also important to point out that the technical review committee that was used in the 2016 Idaho solar study consisted of primarily utilities, nonprofits and researchers that were experts in kind of evaluating this cost, people from the National Renewable Energy Laboratory, from universities. And so to the extent that it was a technical review committee to try to determine the most accurate cost, I certainly would support that, but when you start to look at involving specific renewable developers and that in a technical review committee, you start to perhaps muddy the waters. And I think that it's important just to point out that the Idaho committee did not, to my knowledge, include any renewable energy developers.

REDIRECT EXAMINATION BY MR. DODGE:

Q I just have one follow up with Mr. Hinton. Mr. Hinton, just a few moments ago Ms. Fentress was asking you a few questions about renewals, contract renewals, and specifically about negotiated facilities, facilities that were no longer eligible for standard offer or were not eligible initially. Do you have your testimony with you?

A (Hinton) Yes.

Q On page 14 you describe negotiated contracts briefly. And I just wanted to clarify one point. I think you -- you indicated that if a facility was not modifying how it's operating, you know, an existing facility was coming in to renew, you know, uncontrolled solar generator, that the 12-month window that was described in Duke Witness Johnson's testimony was appropriate, but you indicate here -- looking at lines 7 through 10 or so, you describe circumstances where a negotiated facility that might be making significant changes, such as the addition of long lead time equipment, other things, things that are currently applicable in the context of a new facility that's experiencing delays, that's what you were describing when you said, you know, that a longer time may be appropriate if they're adding battery storage or making other kind of significant changes to that negotiated facility?

A Correct. A standard renewal of an existing QF that wasn't adding storage or making any dramatic changes to its output would -- would -- should be able to consummate a renewal contract in 12 months.

MR. DODGE: Thank you.

CHAIR MITCHELL: Questions from Commissioners?
EXAMINATION BY COMMISSIONER BROWN-BLAND:
Q Good afternoon. Mr. Thomas, you're aware that the Commission has asked Duke to provide a late-filed exhibit with the actual history of the operating reserves at a granular, more discrete level, correct?
A (Thomas) Yes.
Q And did the Public Staff look at that -- that data in assessing the model and its results?
A We looked at the 2015 data, but we wanted to -- we wanted to be wary about going back too far because we just understand that what dictates operating reserves depends on many, many factors. And we also wanted to make sure that we weren't going too far up because there were additions of solar that kind of had been added since 2015. So we -- we thought that when Duke provided the 2015 information, that was -- that was enough to kind of at least assess the reasonableness of the model, but -- so yeah. That's...
Q And then how did you use that data? In other words, in looking at that data, what was your -- why was it important to do that, and what was your interest?
A Well, if the model -- if the no solar model had predicted 1,600 MW to achieve this 0.1 LOLE FLEX metric,

but then we looked at 2015 and we saw, well, actually, the Duke system, it had closer to 2,200 MW of reserves, or maybe it only had 1,000, then we might look at the LOLE FLEX metric and say, well, you know, I think that the metric is perhaps too -- too standard, too tight or maybe too loose, and maybe you need to adjust some parameters in the model to bring the predicted reserves back in line with the -- with the actual reserves.

Q When that exhibit -- when a late-filed exhibit comes in, will the Commission be able to draw some relevant conclusions from that data, do you think?

A I believe so, and I -- I anticipate reviewing it as well when it comes in, but I think, you know, if -- if we see that the reserves that they're operating in some of those years are -- are just wildly different than what the model is predicting, then I think it -- it might require some additional consideration. But I think it's important just to note that getting it close to what the model had in it is important, but also just understanding that there are many factors that -- that influence that. So if it's 100 MW less than the year before, that doesn't mean the model is wrong. It may just mean there's additional considerations that haven't really been controlled for when you just look at the total.

Q And when the Commission looks at it -- takes a look at the data, what would you recommend that we look for or -- and/or what approach should we take in reviewing the data?

A If I were reviewing the data, I would first compare it to the results from the no solar case, or in the case of more -- of the later data in the 2018 I think you asked for, perhaps compare it to that first -- first tranche, but really what I would be looking for is any massive variations between the actual and the model results, and then if there are, you know, trying to push Duke to understand is this a problem with the model or were there extenuating circumstances in that year that maybe would have resulted in higher reserves than normal or lower reserves than normal.

Q All right. Now, Ms. Cummings asked you about the technical review committee, I think, from -- from the Idaho study, and you indicated it would be -- that that was -- that group was made up of utility experts and other technical type experts, university folk, academicians and so forth, and that you -- the Public Staff wouldn't recommend, necessarily, developers be included on that kind of process, but would you find it inappropriate if an equally experienced credentialed person, you know, somebody that -- that the experts -- that speak the same language as the experts and have background and experience, if they happen to be associated with developers, would it be inappropriate to include one or more in that process?

Q I don't think it would necessarily be inappropriate. I think what -- what the -- the Idaho study and the technical review committee did is it focused on bringing in experts that could help to make the charges as accurate as possible, and bringing in NREL and university experts to -- to review the model and the assumptions made, that's -- that's all in the interest of making it more accurate. But I think we're -- you just need to be careful bringing in other parties, market participants who -- who have a dog in the fight, have an interest in maybe reducing the charge. At that point, you know, you need to just be aware that those interests may conflict with the interests of accurately quantifying the charge.

And just on that note, I would say that, you know, as the Public Staff, we also are -- we have an interest as well, and similar to the -- the Idaho study, I think where they took regulatory staff and they were observers to the process; they did not have -- they're not on the direct review committee, and so -- and so even the staff were excluded from that. So I think that's just kind of where you have to draw to line, is you have to make sure that you understand the interests and the motivations of the people who are participating in the review committee.

Q All right. Thank you for that. Now, when Witness Kirby's testimony was filed in this docket, what steps did the Public Staff take to look behind his positions and the component parts of his position?

A Sure. So as it was certainly reflected in our reply comments, we did review Kirby's analysis of the LOLE FLEX. Upon its face, and particularly when he was discussing the Idaho study, internally the Public Staff had -- we had many, many discussions about this charge and the comments. So we read his comments; we took them under advisement. The group decided that, hey, these may be legitimate. I think they need to be looked into more.

At that point we really started to review other studies because, you know, Mr. Kirby almost exclusively relied upon the Idaho study to make this comparison. So we started to look at other studies to see how they were modeling this and their results. And then it was really a deeper review of the Idaho study that kind of started to make us question the conclusions that -- and the comparisons that Mr. Kirby was making, and that's why our position changed between our reply comments and our -- the testimony that I filed.

Q And what were the other studies that you looked at, if you recall?

A Sure. It's Exhibit C, I think, in my testimony, but I -- just real quick here, I think -- we looked at PSCo studies, Arizona Public Service, Idaho -- several studies from Idaho. We looked at a Navigant study from South Carolina from SCE&G. And also -- well, also in my testimony, NREL did a very handy review of integration studies. It was a bit dated, which is why I didn't include it, but just -- they looked back at numerous studies and went into detail about each of those study's methodologies and its findings. So -- so we really -- I tried to get a selection of these integration studies, and the NREL review provided additional background on kind of how this analysis methodology has evolved over the years.

Q So you would characterize it as you spent a great deal of time analyzing the position of Mr. Kirby?

A Yes. I would characterize the...

Q Did you come to the position that he was in error or -- or more that even if he was correct, that it was not -- not determinative or so relevant?

A I would -- I came to the conclusion that I felt that Mr. Kirby relied heavily on -- while Mr. Kirby is certainly a knowledgeable person and I appreciate his analysis of the studies, I found that I came to a different conclusion about how the Idaho study was conducted by digging into methodology. And perhaps I had a better understanding of the -- of the Astrapé model as well, which allowed me to look at the comparison he was making and really relying upon to make his point and come to the conclusion that it -- it was not the same conclusion that I was reaching.

Q All right. The Public Staff and the Company agreed on an avoided cost structure that provides for additional granularity, and that's what was addressed in the Stipulation; is that correct?

A The original Stipulation, the rate design -- I call it the rate design Stipulation, yes.

Q All right. And did the Public Staff analyze the avoided cost rates that would apply to each of those granular buckets, recognizing both energy and capacity components?

A Yeah. We actually did a -- several iterations in kind of coming to the buckets that we had come to, so we had a data request where we had them rerun some numbers, then we -- we took some of their suggestions about, you know, broadening the premium peak windows into consideration, changing some of the months. And they did rerun some of those numbers for us during the Stipulation discussions, but those -- those actual rates, I don't believe, were ever filed until possibly the most recent late-filed exhibit.

Q Were the rates themselves important to you and the Public Staff in terms of accepting the Stipulation structure?

A No. We -- we were really -- what we were focusing on was defining the buckets to appropriately match the avoided cost to the actual avoided cost to the system and -- and the rates would fall out as they -- as they would. We wanted to get the -- the design right. Mr. Metz may --

A (Hinton) Just to add, I mean, the actual core avoided energy rates came out. They were fine. And we reviewed those, and we felt comfortable those rates were reflective of the -- for the immediate term, the two-year variable rates, for example, were reflective of their avoided cost. Not wanting to rehash that issue, but, of course, the Public Staff has issues with other -- with their natural gas price forecast, which would affect avoided cost down the line, but we did look at it at the beginning.

Q All right.

A So within that caveat of our other positions.

Q Thank you. So am I correct that the Public Staff has not agreed with the Company on the gas inputs for modeling?

A Correct.

Q And without that, it's impossible to file a joint proposal with the Company for avoided cost rates associated with each of the granular baskets?

A That is correct.

Q Okay. Do you think that the stipulated structure provides an opportunity to appropriately signal that there are different costs to be avoided during these -- this granular -- the granular periods?

A Yes, we did.

Q All right. Do you have any position as to the rate differentials?

A Between what -- the original filing and what we proposed would possibly fall out with using an updated natural gas forecast that didn't go for -- the one we

recommend?
Q Well, between the -- the different periods.
A (Thomas) Just to -- could you clarify -- restate? I just want to make sure I get it.
Q Well, just -- I had asked about did -- was there opportunity to appropriately signal the different costs during the different granular periods, and did you have a position as to those rate differentials?
A Yeah. I think when we looked at -- we looked at a blend of historical and projected cost data from the Utilities, and what we attempted to say is the premium peak represents the most valuable time for energy. And then the on peak is the next most valuable, then the off peak. And so to the extent that we took a position on the differentials, we would assume that the premium peak would be higher than the on peak, which would be higher than the off peak, and that would be the signal by which the developers would modify the facility, potentially add storage, or operate in a way that would avoid the highest utility cost.
A (Metz) I agree. I mean, the rate structure mimics the value of the energy and capacity on the utility system. I believe we used the five years of historic data because, again, avoided cost is looking

forward. We used five years of forward data, and we more or less used five years of a blended historic data, more or less trying to get -- the terminology used is a calibration. We wanted to make sure that the forward forecast, this wasn't too far out of line, so we blended it between the two.

Q All right.

COMMISSIONER BROWN-BLAND: Thank you.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Good afternoon, gentlemen. Between Mr. Smith earlier this morning and Commissioner Brown-Bland, they have saved me an awful lot of work and saved you an awful lot of time, so I just have a few gaps to fill.

And I want to go back to the line of questioning that Mr. Smith was exploring with you about the implications of establishing an avoided cost in this proceeding that would include a systems integration charge, the implications of doing that and how that would play out where we are applying the avoided cost concept to other programs, non-PURPA programs. And I -- I'm not going to cover any of the ground he did because he covered it very well with you guys, so I appreciate it, but there was one program, Mr. Hinton, I think, and that's the REPS cost recovery program through the rider where avoided cost sets the -- the -- well, essentially, the trigger beyond which you begin to determine the increment that's eligible for recovery under the rider.

So what is the Public Staff's view about -- let's make the assumption that avoided cost means the same thing across all statutes. Let's make the assumption that -- also that the systems integration charge is, as you see it, a component of avoided cost. So with those two assumptions made, how would the Public Staff envision that the avoided -- this inclusion of the systems integration charge in the concept of avoided cost would play out in the REPS proceedings?

A (Hinton) Similar to how we see it falling out in the demand-side management energy efficiency cost rider programs. And that -- well, let me strike that. Let me strike that. We haven't -- unless -- would someone else -- I don't think -- go ahead.

Q If you don't have an answer today, that's fine.

A (Metz) I --

Q If you do have an answer today, I was just going to see what it was.

A The REPS rider is recovered through fuel -- not rider -- the REPS charge that's recovered through fuel is anything at avoided cost or below, and then the REPS rider takes care of anything above -- incremental amount above. So to the extent that the REPS bucket and the fuel has a bunch of legacy projects, I mean, those would be exempt, I mean, how we laid it out here before, but as the projects are renewed, any solar QF, it would have to be taken in consideration so that way it's a consistent methodology placed across the board.

A (Hinton) I agree. That was my mistake.

COMMISSIONER GRAY: Please use the mic.

A I'm just agreeing with Mr. Metz, that the SISC charge would apply to any new QFs or renewable QFs with regard to the REPS rider -- REPS solar QFs.

Q And that's -- that would be a little different than the way you articulate -- and I understood your explanation of why you didn't think that would come into play in the DSM/EE program, but since REPS is a bucket of presumably uncontrolled solar projects, some are legacy and some will not be legacy, I had to ask the question because it might have a different -- different way it played out.

A (Thomas) If I could just --

Q Of course you can.

A -- talk a little bit about that --

Q Absolutely.

A So if you were to --

Q I just want education, so talk.

A So I think if you were to reduce the cap applicable to the REPS and the interplay between REPS and fuel, by the avoided -- by the integration charge, you would -- essentially for legacy projects that are being recovered under fuel and REPS, you would shift the -- the ratepayer is normally paying for the integration cost and fuel, would now be paying for it in REPS.

Q They'd be paying for it in REPS.

A So I think it would be a meaningless shift. And since Duke has also stated that the -- any money collected by the SISC would be flowed back through fuel, it would appropriate, I think, to exclude the SISC from the avoided cost in REPS and then just keep that all in fuel to be flowed back at a time when it's eventually collected from all solar QFs.

Q That's very helpful. And thank you. Gets me where I need to get, for today at least. I think the purpose of the questions that you were getting from Mr. Smith and some from others and from me is that -- is that if we're going to pack another concept, another construct altogether into this avoided cost, then we have to really work very hard to figure out how it flows through these non-PURPA statutes. That's -- that's going to be some additional work beyond today for you.

A couple other quick things, Mr. Thomas, when you were answering one of Commissioner Brown-Bland's questions and you were referencing the other studies you looked at, you referred to one you didn't list in your -- in your exhibit, and that was the older NREL integration study. Was that -- by any chance, was that the integration study that Mr. Kirby authored that I asked him about the other day, the NREL integration study that I asked him about from 2011? Is that the one you looked at?

A No. This is -- this is a review of variable generation integration charges, and Mr. Kirby is not on the author list.

Q He's not -- not one of the co-authors? Okay. Thank you.

A And this -- and the date of this study -- or it's not a study, it's a review, and the date is 2013.

Q 2013.

A So I just relied upon it kind of to show me the evolution of how this charge is being --

Q Thank you. I just -- I was curious as to whether it was the same one that he had co-authored.

Okay. Staying with you, Mr. Thomas, on page 9 of your testimony, you -- I'm going to read it to you, so you don't have to worry about it. On -- beginning on line 12 you said, "The Public Staff had a conference call with Duke system operators who spoke in detail about the process for scheduling the load following reserves necessary to respond to intra-hourly fluctuations and solar output and load. This process does not incorporate any data from other utilities, that is, when DEP sets its required ancillary services for a particular day or hour, it does not consider the state of the DEC system." I understand what you said.

Let me ask you, because you referred to DEP and DEC in that -- in that illustration, did -- was your conference call with the system operation of both of the two Companies, or do you remember who you spoke with?

A (Metz) I can't remember which particular operators were on that phone call. I would have to go through our minutes and look through, exactly who was on that phone call.

Q Well, I'm just curious. By any chance, was Mr. Sammy Roberts one of the people you spoke with, because he's been in the hearing room --

A Yes.

Q -- even though he hasn't testified?
A Yes. I believe Mr. Roberts --
Q Mr. Roberts was on that phone call?
A Yeah. I'm just trying to remember all the other players that were in that.
Q But were they from both companies?
A (Thomas) Well, I believe that they brought in actual system operators. There were -- there was at least one or two people actually sat in the chair, and they came in and talked to us in the conference call.
Q Right. I understand. Maybe I'm not clear in my question. But you say when DEP sets its required ancillary services, it does not consider the state of the DEC system, and I wanted to know if your -- if your interview disclosed to you that the same was true for DEC --
A Oh. I --
Q -- that when they set their instructions, they didn't consider the state of the DEP system? I just want to be sure.
Q I think -- if I remember right, I'd have to check the notes, I think we only talked to system operators from one BA, but --
A Okay.

Q -- in that case I think we made the assumption that it was the flip, and Sammy Roberts may have provided some -- some discussion about that that confirmed that. But whether we talked to -- to DEC or DEP, the bottom line that we came away from the -- Sammy -- the conversation with Sammy Roberts and the system operators was that this -- this concept of relying upon non-firm transfer between the BAs is not sufficient to rely on for ancillary reserves.

Q Well, did you explore, in your conversation with the folks you spoke with, whether or not the practice that they followed was standard in the industry, or unusual or uncommon or something specific to vertically-owned utilities in the Southeast? I mean, did you explore whether this was a standard practice of not considering non-firm resources available from neighboring utilities?

A I --

A (Metz) No, I did not.

Q I'm just --

A No, we did not.

Q All right.

A But to that extent, is reading sort of -- reviewing the NERC standards that are applicable and how you cannot -- general concessions you don't -- you just don't go lean on your neighbor unless you have to.

Q Right.

A And through that discussion they were providing NERC citations, and we believed it was reasonable at that time that they were taking a reasonable approach of how they were addressing the ancillary services. I mean, because the other -- other component that was playing into this was the JDA. I mean, the JDA is based on a non-firm uneconomic basis, and that was discussed extensively in the Sub 148 proceeding. But with that in mind, is the Utility -- or as Mr. Roberts -- Sammy Roberts was -- my recollection that I recall is that from ancillary services, they have to solve for ACE. That has to be firm. And, therefore, that has to be out of the BA because we cannot rely on non-firm transmission paths or the configuration or differential changes of transmission paths.

Q And -- and so those conversations you have where the basis on which you sort of moved away from your initial concern that you shared with Mr. Kirby about the islanding issue?

A Yes, sir.

Q Okay. Okay. A couple last questions about Mr.

Kirby. So -- so did you -- and Commissioner Brown-Bland touched on some of this, but I want to sort of probe it a little bit more. Did you actually speak with Mr. Kirby when you did your investigation on the Astrapé model? Did you talk with him about the concerns that he had put in his written comments?

A We talked to him once or twice. I know -- I know at least once --

Q You did do that?

A -- but I remember twice, and I also remember reaching out, it was shortly after the state energy conference. I just remember that and --

Q Okay.

A -- then we came back and we had a little group meeting and said let's reach out. But, yes, it was once or twice and the possibility of a third time --

Q Okay.

A -- going off memory.

Q Thank you. Memory is all -- memory is all you can give me. Okay. So we've been through this many, many, many, many times, but we're getting in the short hours here, so -- or short minutes. Excuse me. In the short minutes. So I want to just ask it one last time to see if I can get it wrapped up in a nice package with a bow on it.

So after you heard Mr. Kirby here for another two days and you've talked to him a couple times and you've read all of his comments, give me the shorthand version of why you're still not persuaded about his critique of the LOLE FLEX metric.

A (Thomas) I think --

Q Shorthand version.

A Sure. Short as I can. Mr. Kirby's statement yesterday that perfect foresight in the two models was a red herring, I think that summarizes my disagreement with him in the best way possible. It is not a red herring. It is a fundamental difference of the two models and the way that they were -- the variability and the reserves were calculated. And that is a short version. I can elaborate if you want, but that is really where -- the core of it.

Q You might need to elaborate for others, but I understand you exactly because you heard my questions yesterday. Thank you.

COMMISSIONER CLODFELTER: That's all I have.

EXAMINATION BY CHAIR MITCHELL:

Q A few questions. I'm going to go to you first, Mr. Thomas, since I'm going to just sort of piggy-back on

-- on Commissioners Brown-Bland and Clodfelter. Briefly, give me your understanding of Mr. Kirby's conclusion regarding the method and your explanation for why you've come to a different conclusion than Mr. Kirby.

A So Mr. Kirby looks at the Idaho study and he says that the Idaho study allows load and generation to be in balance 90 hours out of the year. That is fundamentally not how I interpreted the Idaho study. The Idaho study, outside of the model, looked at -- it compared actual generation to a manufactured forecast, and then it calculated the error in each 5-minute bucket, comparing actual 5-minute generation to this manufactured hourly forecast. It threw out the top half percent, the bottom half percent of that variability and said what I -- the reserves I need, the up and down reserves I need is enough to cover what remains.

And then they put that -- those reserves into a production cost model that knows -- it's a one-year model. On January 1st it knows precisely what the load and the net load will be on December 31st. It knows it all throughout. So it dispatches its resources in a way to meet load and generation in every hour. And the study itself explicitly states that load and generation, it's a constraint of the model, it must be met. If it's not, the model will not solve. So it's literally impossible for the Idaho study to ever miss load and generation.

Versus comparing that to the Astrapé study where there's uncertainty in the model, there's thousands of model runs, and that uncertainty resolves as you get closer to the -- the actual event, until at that 5-minute variable you have to check to see if you have the capability to meet load with what you already have online, what you committed an hour ago, a day ago, a week ago, what you've committed to have online now, including the reserves that you've set aside. Can you meet load, knowing it perfectly in advance?

And so Mr. Kirby tried to make the comparison that covering 99 percent of the variability in net load in the Idaho study compared to not having the ability to meet load in a -- knowing exactly what it would be in five minutes, and he tried to compare them, that's not a valid comparison. You're looking at two really different things. And so -- so that's really where -- where the core of our disagreement is about the interpretation of the Idaho study and the Astrapé study.

Q Thank you, Mr. Thomas. I -- I very much appreciate that.

A Sure.

Q Okay. Mr. Metz, a few for you. Solar clipping. In the case of a facility -- a solar facility where the generating capabilities or capacity of the panels exceeds the capacity of the inverter, and there is no storage facility tied to the PV facility so it's just a stand-alone solar facility, what happens to the electrons that are generated, given the limitations -- generated by this sort of oversized facility, given the limitations of the inverter?
A (Metz) The short answer, heat. It's waste.
Q It would just dissipate as --
A Just dissipates. That gets to sort of thermal ratings. I mean, it's wasted energy. It's not utilized and it's dissipated as heat. Short version.
Q Okay. Second question, in the -- the case of a facility that -- a solar facility that includes an energy storage facility, does clipping result in the sale of additional kWhs or does -- does clipping result -- clipping result in the putting of additional electrons to the system than otherwise would have been occurring with no -- with no energy storage?
A So following exactly back up to the pre--- the question you asked me previously, battery storage will allow you to use the wasted energy, and it can be

utilized at a later time which would be an increase in kWh because it would be generation that basically you threw away --

Q Yeah.

A -- and then you get to use it, but now you're using it later because you stored it --

Q Okay.

A -- including efficiency losses. I mean, it's not a one to one, but it is additional sales.

Q Understood. Okay. Thank you.

CHAIR MITCHELL: Okay. Questions on the Commission's questions?

MR. SMITH: I just have a couple.

EXAMINATION BY MR. SMITH:

Q And I guess this goes to Mr. Thomas. Talking about Commissioner Brown-Bland's question about the technical review group, it triggered two questions for me. The first is, understanding that NCSEA is not taking the position that they shouldn't be involved in any technical review group, but understanding that, does the Public Staff have any concern in Duke being included in a technical review group, under the -- under the assumption that they're a market participant in this CPRE and, as we've discussed today, any solar integration charge would be implemented on that program?

A (Thomas) So first of all, I think that it would be impossible that a technical review committee -- to help with the study without the Utility being involved, so I'll just start with that. But there's two concepts here. First, as it's been pointed out, I believe, in Witness Snider's testimony, the Utility is passing on these integration charges and this collection of the SISC as a flow-back to ratepayers, so putting that out there. And then with the assumption that CPRE would equally apply the SISC to both Utility projects and third-party market participants, I'm not sure that there would be concern that Duke would try to influence results up or down, one way or the other, because they know they are going to be on the same footing -- well, a lot hasn't been decided with how it will be implemented in CPRE, but they should be on the same footing as a third-party participant.

A (Metz) And just to potentially add, is when you -- in my experience, when you get into larger committees like that, there's a vetting process. I mean, even to the extent where a developer or even the Utility -- I mean, there has to be boundaries drawn. There's layers of separation. So you take a system operator, well, the system operator isn't going to be talking to the arm of the Utility who is a market participant. I mean, where I've worked on the NESC Subcommittee 3 where we have solar developers there, I mean, it's more or less the -- the engineers are trying to work through solutions to allow safety protocols that are not pushing a policy, but in submittal to that committee, I was properly vetted.

Q Thank you. And just one follow up on that because I think this does touch on that. Uncontrolled solar owned by Duke, how does the Public Staff understand that that will deal with the SISC in terms of cost recovery or in other implications that you all might have talked about?

A (Thomas) I think I addressed this in my testimony, but the -- the uncontrolled solar generators owned by Duke also incur additional ancillary reserves that are required to integrate it, and those costs are borne by ratepayers right now, just the same as the cost of a rate-based gas plant are borne by ratepayers. So that -- that's --

Q Okay. So -- so my understanding is your position for uncontrolled solar owned by Duke that incurs this SISC would -- it would just continue to pass on to the ratepayers with projects as it is now? Is that -- is that what you're saying?

A Yes. It would continue to pass that cost on to ratepayers, but in the context of evaluating bids in the CPRE, it's important that they be treated the same. So like I said, you know, whether it -- the SISC is used to reduce the cap, which might kick out Utility projects that aren't able to get below that cap or -- or how -- if it's assessed during the evaluation process to -- to look at uncontrolled solar generations and levy that charge during the evaluation, it just has to be applied equally. But when it comes to actually paying for the reserves that Duke requires to have on the system to integrate its own solar, that -- I mean, that's going to be borne by ratepayers.

Q Last question, I promise. Do you understand that within the competitive procurement process, that if Duke -- and I think I heard you right -- can cost recover for the SISC, that puts them in a different position than in -- for third-party developers? And correct me if that's mischaracterizing what you just said.

A No. I -- yeah. I understand. That's why it's a different situation. That's why, I think, you know, the examples I'm using are -- are talking about pushing down the cap or using it in an evaluation process. You know, if you were to simply charge, you know, say, okay, I think any PPA signed on this CPRE is going to include the SISC, first off, I think that, you know, you have to think very carefully about how you do that and -- because that does introduce, to your point, some uncertainty. If Duke can simply pass those costs on to ratepayers, then perhaps they're not as -- they have a leg up. But, I mean, I'd also note that, you know, that I believe CPRE projects that are self-builds are cost recovering on a market basis and not a cost of service basis. So there may be some ability to work it in there, but like I said, there's just a lot of unknowns, and I think the Public Staff's interest is just making sure that both the Utility owner and third-party are evaluated equally in the CPRE. And we still need to work out those details to ensure that the Utility does not have a leg up on third-party generators.

Q Thank you.

MR. SMITH: Nothing further from me.

MS. BOWEN: Thank you. I do have a couple of follow ups.

EXAMINATION BY MS. BOWEN:

Q They're probably for you, Witness Thomas, but feel free if it makes sense for others to answer. So the first couple are just in response to some questions from Commissioner Clodfelter, and you -- and I believe Mr. Metz described a call or meeting with some system operators for the Utilities. And I know you talked about not leaning on your neighbors and the joint dispatch agreement among the Utilities and, you know, potential to transfer firm capacity. Did you all also discuss or get into the question of the distinction between that and the actual physical interconnection to the Eastern Interconnection?

A I believe, and Mr. Metz might elaborate, that this call was primarily focused on how Duke schedules their reserves and sort of just how they operate their system. We -- we didn't really discuss, I don't think, the larger Eastern Interconnect.

A (Metz) No. The larger Eastern Interconnection wasn't taken into consideration in these conversations. Again, as you read the NERC standards, the Utility's obligation to meet load under certain time intervals, under certain restraints, under certain planning restrictions, we found very persuasive and -- and led to our ultimate decision.

Q And Mr. Metz or Mr. Thomas, you all have seen, I assume -- they've been passed around a lot -- you've seen the NERC standards?

A (Thomas) (Nods affirmatively.)

A (Metz) (Nods affirmatively.)

Q Okay. And -- I think that's a yes for the record?

A (Thomas) Yes.

Q Okay. Thanks. And they -- and they do -- there -- it references the Eastern Interconnection and the reliability metrics that are imposed, if you are a part of the Eastern Interconnection, as opposed to some other location in the US?

A (Metz) Right. I believe the one that's been passed around the most is BAL-001. And to that degree, yes, each -- each entity, if you would, or Eastern Interconnection, Western Interconnection, ERCOT, each has the beta coefficient that would be plowed -- connected into or be part of the equation for the ACE error. As I tried to point out here, there's other BAAL standards that go hand in hand, not just with ACE. I believe that one that I also discussed was the BAL-002, which I believe was the revision from the CPS2 standard, even to that where the Utility has to respond within 15 minutes for a contingency reserve.

As you start starting to drill down these layers, I believe Chair Mitchell brought up the conversation of VACAR through SERC. VACAR is a member of SERC. I believe that initial charter was established approximately 2005, a bunch of members. SERC has since expanded and VACAR -- apologies -- SERC reformed their districts. VACAR changed. Now it's VACAR Southeast. VACAR Southeast is a component of the North Carolina/South Carolina utilities.

I haven't been able to tease out the, exactly, contingency reserve, but going back -- so in 2005 under VACAR, that there was approximately 1,600 to 1,700 MW of contingency reserve. And between Duke Energy Carolinas and Duke Energy Progress, they are approximately on the hook or responsible for about 50 percent of the total contingency. I mean, it's based upon larger -- the largest generator and the ratio of load. And to that extent to where the VACAR region has changed, their contingency reserve amount would change. Where I'm going with that is it ties back into BAL-002, that we're no longer talking about 30 minutes, now we're talking about 15 minutes. The Utility has to respond within 15 minutes to tie it back to its ACE value before it started. Because then if you read further chap--- or sort of the top part of the -- the VACAR, that you cannot lean excessively on your neighbor, and that's the point that we're getting here.

Q Just to confirm, though, your testimony was that you didn't discuss the physical interconnection aspect of this and the Eastern Interconnection, the difference in the standards there.

But just to move on, you just mentioned the 15-minute interval. We know there's also significant 30-minute intervals. Regarding the perfect foresight in practice and meeting the NERC standards, it's -- a 5-minute balance deviation is not a FERC violation. It's longer than that. It's a longer time horizon than that.

A Correct. It is a longer time horizon. Now, to the extent where I would want to tell the Utility is let's go all the way up to that number? I believe Mr. Kirby had alluded to this. What is the right number? Is it 20 minutes? Is it 25 minutes? I can't tell you. The only thing is that we've had multiple conversations throughout the year with the Utility, not as dealing specific to these issues, but the Public Staff has multiple meetings with the system operators as we're learning how the system operators are responding to the system. It is not in the Public Staff's position to tell the Utility how to operate the system. There's other regulatory bodies, and their control is to ensure the safe operation of the system.

A (Thomas) If I could just elaborate a little bit. So the call -- the purpose of the call that you're kind of digging into was really to decide if -- to understand if Duke Progress and Duke Carolinas were coordinating in their scheduling of reserves. And if that was the case, then we might look at that islanding model run or the joint dispatch model run that was in Mr. Wintermantel's testimony and say, hey, maybe that's more appropriate to calculate the charges because, look, you guys are sharing reserves to integrate this intermittency, but that -- they weren't, and that was the point. And I think -- I just want to push back against comparing these 5-minute violations in the Astrapé study to the NERC violations.

So, you know, if -- if you're betting on sports and you're wrong half the time, that's expected, but if you're betting on sports and you have a sports almanac from 2025 and you're wrong, there's a big problem there. So, I mean, this is -- it's not the same violation. They're coordinated -- they're correlated. Not having the ability to ramp to meet demand is certainly a problem if your system doesn't have that capability. But to say that -- looking five minutes out and knowing exactly what net load is and you still can't meet it, that's a pretty serious violation, versus chasing that unknown and uncertain load, as system operators truly do on a minute-by-minute basis. So I just -- I know we keep coming back to comparing NERC standards to the LOLE FLEX and the 5-minute variations, but it's truly not the same thing. And the -- the perfect foresight is a fundamental reason why these two metrics are different and correlated, but not comparable on a one-to-one basis.

Q Okay. I'm sorry. So when you're referencing the -- the perfect foresight, in particular, and you say it's a violation, what is it a violation of?

A So it's a -- it's saying that your system does not have the capability to meet load, knowing exactly what it would be. So in this situation you don't have the reserves available, you don't have the ramping capability. Your system is literally not able to -- to meet that load. It's a much -- it's a much more serious violation, I feel, than chasing load on a minute-to-minute basis.

A (Metz) Violation of the model, not violation of a NERC standard.

Q Thank you. And then just following up on something you just said, and I -- I do want to make sure we're not ending up in a place where we're reframing, basically, the solar integration charges. Is it -- is it a flexibility -- you know, Utility and flexibility metric, so I want to take it kind of higher level, and I think this gets to actually one of Commissioner Brown-Bland's questions about comparing the base case and some historical data and, you know, what is -- how is the Utility actually operating.

So here's my question, if this grid integration charge is implemented, what incentive does Duke have to move towards a more flexible fleet?

A (Hinton) That is a concern in the IRP, if moving to a more flexible fleet would lower the operating cost and capital revenue requirements for the expansion plan. As a -- as a -- the system grows and changes, they'll evaluate those units. They do now in the IRP. They have these fast RCTs and other units that can do -- that will enable the unit -- the Utility to be more flexible. So that incentive exists today.

Q So -- and let me ask it one more -- a different way, and it still may be for you, Mr. Hinton, or someone else, but when we're talking about the base case that's being analyzed and updating that base case to reflect changes in Duke's fleet, doesn't Duke have an incentive to keep the fleet inflexible if it can impose the cost of that inflexibility on -- on solar producers?

A (Metz) I mean, one element and how we're looking at it, I mean, it's a pass-through, but as we're talking about the SISC charges being flowed back and there's -- and there's other conditions that we put into the Stipulation, and that can speak for itself, that we -- we believe, at least, are reasonable controls to help mitigate some of the concerns that we identified, as the Stipulating Parties, to look at other elements.

The -- it would be my understanding at this time, as -- if the Commission were to adopt SISC charge and drop the Astrapé methodology, with whatever revisions that take place, and we're here two years from now, so we fast forward. I made the statement earlier that the burden of proof is still on the Utilities to demonstrate that the model is appropriate. To that extent, whether we use the 2015 base case, the 2018 base case, I can't tell you what we're going to do exactly from two years now. We just agreed to the overall methodology. What I think Mr. Thomas alluded to earlier is that the system -- and I'll let him speak from the modeling's perspective --

but how the system is configured, in other words, what plants that we have currently in the operation characteristics should be inputted into the models. That way we can have the best base case with no solar volatility as possible, is a reasonable estimate -- or a reasonable measurement point.

A (Thomas) And I would just -- to add -- the only thing I would add to that is there's a lot of reasons, other than simple solar volatility, that Duke might want a more flexible fleet. And so they are going to work towards that, and to a certain extent in the IRPs, some of the integrated system operation planning that they're considering. So, you know, there's certainly incentives in more than just paying for the integration of -- of volatile solar to make a -- your fleet more flexible.

Q I have a follow-up question. Okay. Sure.

A (Metz) So as -- I know the things that we've identified in the IRP is where the Utilities sort of started bringing this issue forth to the Public Staff, and I believe they brought -- mentioned, especially in the Sub 148 case, is the overall limitation or looking at how far can we dip base load nuclear in the current state of the Carolinas. As we get into the shorter months and we have these -- the solar starts coming online, most known -- in DEP, we have currently the higher penetration, and DEP is -- we have more generation or load, then we dip down into the nuclear, so I've got to start shutting down plants. I have the ramp rates. Through the IRP process Mr. Hinton alluded to, the IRP needs to solve for those ramp rate restraints. Now, I can't say that's an incentive. All I'm saying is it's the Utility's obligation to ensure that our lights stay on or they get in trouble by NERC and I bet they'll get in trouble by this Commission as well.

Q So understanding that incentive, that they do need to keep our lights on, and also the incentive of, you know, if they're able -- I understand the incentive if they can make a capital investment, earn a rate of return on that. Those are incentives. What are -- what are the other incentives to -- and let me -- let me be more specific. What are the other incentives to operate the fleet, knowing that -- we all, in this room, acknowledge we are moving to a different electricity system, a different method, a different way of producing electricity than we have for the past 100 years. Everybody gets that.

So other than the ones that we just talked through, my concern is that if you are passing through this charge, the operators are not going to -- or not the operators, but that Duke Energy is not going to be incentivized to make the fleet more flexible if they're just passing through that charge. So is there anything else, other than those -- those ones that we just identified?

A So the one element of passing through, one, it's flowing back to the people who are being borne the charge, ratepayers. If you're talking about currently, the ratepayers are paying for solar volatility. So the cost will flow back to the people who are currently paying them. Another element to look at of how -- from the Commission's oversight and part of our investigation, when the Company comes in for a general rate case, we open up the books and we go through extensively. This will be a chapter and part of that consideration of how the Utility, lack of a better word, grid modernization or some other element is taken in effect to include more flexible resources.

There's also -- there's a CPCN process when the Utility comes in. I mean, there's a bunch of other regulatory check valves to -- to validate some of these concerns or help mitigate some of these concerns. I understand, I mean, your concerns and where you're coming from. I don't have a perfect solution, other than saying there's other milestones in place to help address some of these issues.

Q Okay.

MS. BOWEN: Nothing further. Thank you.

MR. BREITSCHWERDT: Just a few questions.

EXAMINATION BY MR. BREITSCHWERDT:

Q So Mr. Metz, you heard from Ms. Bowen again about the BAL-001-2 standard. Do you have that with you, by chance?

A (Metz) Yes, I do.

Q Okay. Would you on page --

CHAIR MITCHELL: Mr. Breitschwerdt, we just -- we're on questions on the Commission's questions at this point.

MR. BREITSCHWERDT: Okay. Fair enough.

CHAIR MITCHELL: If you can tie your questions to one of the questions asked by a Commissioner, please do so.

MR. BREITSCHWERDT: Okay. I think I can withdraw that one.

Q Two quick questions. Commissioner Mitchell asked you about the -- the implications of solar clipping for the system, and you stated that clipping is additional sales through energy captured in a battery storage system. Did I get that right?

A One method could be sales. Another method could be reducing the volatility imposed on to the system.

Q So that would be a smoothing operation?

A That is correct.

Q So in the absence of adding storage, if the QF was overpaneled and they were clipping energy, the implication is if they overpanel the facility, that would also be additional sales to the system; is that correct?

A I believe, as I characterize additional energy in my testimony, that if you said -- if I have a vintage project, and for whatever reason they had 200 -- using hypotheticals here, they had 200 MW panels for five years, and for whatever reason the numbers worked, and went and plugged in 350 MW panels across the system and tried to get that additional energy above their baseline, then that would result in additional sales.

Q Understood. Thank you. All right. Commissioner Brown-Bland asked -- Mr. Thomas, I'll shift to you just for one question here about the conclusion to be drawn from the additional data that the Companies are providing related to operating reserves. And I think you identified that if the operating reserves deviated significantly from what the 0.1 LOLE FLEX was, which was approximately 1,600 MW, and I think you used a band something of if it was around 1,000 MW or it was at 2,200 MW, that would identify potential concerns with whether the LOLE FLEX metric was overly stringent or too loose, I think was your terminology. That's a pretty significant band. And I think -- just to confirm, is the reason why that is so broad is because, as it states in the Idaho study, the reliabili--- the metric used is relatively immaterial as long as the base case and the change case, the simulations are consistent and you are running the model to get to the same level of reliability? Is that a fair characterization?

A (Thomas) First, the numbers I threw out there, those were just -- those were more like extremes.

Q Sure.

A Like I was saying, if I saw that, that would jump out at me as a red flag. So I don't know what the band of appropriateness is, looking for a reasonable marginal of error there, but you're right in that the comparative analysis is -- is the most important part, but that being said, ensuring that the base case is fairly accurate in regards to history is important because otherwise, you -- you know, you shift yourself -- if the cost of holding these reserves has an increasing marginal cost, shifting yourself too far along that curve will increase the cost of holding those reserves. So it is important to at least make sure you're grounded in reality for the base case.

A (Metz) To the extent I think it might be helpful to tie in our earlier conversation that Mr. Kirby had, is we talked about -- sorry to go back down to NERC standards, but we talked about the evolution of the NERC standards, and Mr. Kirby had his background knowledge and history of working of the time frames of which evolved from CPS2 to the new BAAL standards.

If you were to work through that and you sort of looked at the time frame that was initiated, approximately 2010, a bunch of voluntary utilities, more so in the WECC region, there was limited from a trial perspective in the Southeast, but there was still some, there was a lot of lessons learned as those developer -- those utilities went into these new parameter sets. And when they went and teased out the data, is that there was an increase in reporting events. It's not to say a violation; it's just as they loosened the band -- or correction -- as they tightened the band, in my opinion, of how they looked at it, more and more occurrences started to happen. And if you were to go through sort of that summary of the WECC chart, they went then further and said, okay, is this a correlation, as if we tightened the standard and the amount of events. They went through there -- and this is my interpretation of the WECC report, January 13, 2015, and they got some good graphs laid in there, and it's on the NERC website. They said for the most part, yes, there is a correlation, however, there's other statistical anomalies that increased in the deviations. Those were storm-related events, weather phenomenon, excess rain. There's -- there's other statistical anomalies.

So to tie that back to the point, as you look at that band width per year, a lot of different factors need to go into consideration as you tease out that data. What is the bandwidth? It's going to vary based upon the events of that year. Sorry for the long answer.

MR. BRETISCHWERDT: No further questions.

MR. DODGE: No follow up from the Public Staff.

CHAIR MITCHELL: No follow up? Just to be clear.

MR. DODGE: No follow up.

CHAIR MITCHELL: Okay. All right. So we've come to the end of the proceeding. Gentlemen, thank you. You may be dismissed. A couple housekeeping matters to attend to.

MR. DODGE: Madam Chair, if the Public Staff could move to -- that the six exhibits included in Mr. Thomas' testimony be entered into evidence.

CHAIR MITCHELL: Hearing no objection, motion is allowed.

(Whereupon, Thomas Exhibits A-G were admitted into evidence.)

CHAIR MITCHELL: Any additional motions pertaining to evidence? Okay. We have a request from Commissioner Clodfelter.

COMMISSIONER CLODFELTER: One more late-filed exhibit. And I'm going to address the question as clearly as I can, but if I get it a little bit off, I think Mr. Snider probably knows what I'm going to be asking for, so he may want to listen. So we've talked a lot about the rates, and I understand you're going to provide us at a later date with the proposed rates for a 20-year contract, à la CPRE type of contract, based upon, again, the same assumptions that you've given me on Duke late-filed Exhibit 1. This is different. So I'm going to look now at the revenue picture.

MR. BREITSCHWERDT: Just with the clarification of the updated fuel for the 20-year.

COMMISSIONER CLODFELTER: That's right. With the clarification of the updated fuel, right, but using the same forward future fuel forecast that -- that you assume -- that Duke has assumed.

MR. BREITSCHWERDT: That's correct.

COMMISSIONER CLODFELTER: Okay. This is -- this is looking at the revenue pictures. So let's take a -- a 1-MW solar project with a 5-year standard offer contract, and let's assume a production profile that's typical for a facility that would be located, say, in central North Carolina, Greensboro area. So pick a facility, standard production profile of a 1-MW solar project under a 5-year standard offer contract. Now, I want to do this for both DEC and DEP. You can pick your facility wherever you want to pick it, but I want to run these -- run this request for both DEC and DEP, okay? And then let's run -- I want to run the Sub 148 rates and see what revenue -- the revenue picture looks like for energy, for capacity, for on peak and off peak and then for total under Sub 148 rates for that hypothetical facility.

I then want you to take the same facility, exactly the same facility, do not change the production profile, assume the same production profile, and then run what the projected revenue would be for that facility under the proposed Sub 158 rates, again, for energy under the rate design that you've got proposed for capacity, under the rate design that you've proposed, and then show -- I guess as a decrement show the proposed system integration charge. Got it?

MR. BREITSCHWERDT: And for clarification, this is for a standard offer QF?

COMMISSIONER CLODFELTER: Standard offer.

MR. BREITSCHWERDT: So that would be a 10-year term?

COMMISSIONER CLODFELTER: Well, yeah. Well, I don't -- yeah. Let's do it for a 10-year term. Yeah. Let's do it for a 10-year term. And I'm really looking for a comparison of 158 and 148, so either way, but let's run it for a 10-year term. Let's run it for a 10-year term so everything is standard. Okay? Did I get it out clear enough for you to understand it? Mr. Snider is signaling thumbs up, so does that mean his lawyers agree?

MS. FENTRESS: If Mr. Snider says thumbs up, we say thumbs up, too.

COMMISSIONER CLODFELTER: Okay. And that would be a late-filed exhibit --

MS. FENTRESS: Yes, sir.

COMMISSIONER CLODFELTER: -- Number 4. Thank you.

CHAIR MITCHELL: Okay. Anything else from any of the Commissioners?

(No response.)

CHAIR MITCHELL: Okay. We have a motion pending from NCSEA regarding Witness Harkrader. I'm prepared to rule on that motion now. I -- before I do so, I want to say a few things, though. At the Commission we have a history of allowing a substitution of witnesses when circumstances so -- so dictate. I also just want to point out that the Rules of Civil Procedure would allow for a party to seek to introduce a deposition transcript when circumstances -- under certain circumstances. With those two things in mind, I'm going to rule in favor of Duke that the motion shall be denied, and on the basis that 62-65 gives -- gives any party a right to cross examine witnesses in the proceeding.

So -- so with that, I don't believe there are any other pending motions before the Commission, so we will turn to proposed orders and briefs. Thirty 30 days from the notice of transcript, unless you all feel you need additional time. Okay. So we will ask for proposed orders and briefs 30 days from the notice of the transcript, and we ask that you all pay -- pay careful attention to addressing all issues in this proceeding, not just the ones that we've heard from you over the course of this week.

Finally, before we adjourn, I want to say how much we appreciate the effort that has gone into this proceeding. This has been a long and arduous period of time for you all. We recognize and respect that, and we appreciate the effort that has gone into this and the professionalism that you all have -- have brought into this hearing room. So thank you, and with that, we are adjourned.

(The hearing was adjourned.)

STATE OF NORTH CAROLINA

COUNTY OF WAKE

C E R T I F I C A T E

I, Linda S. Garrett, Notary Public/Court Reporter, do hereby certify that the foregoing hearing before the North Carolina Utilities Commission in Docket No. E-100, Sub 158, was taken and transcribed under my supervision; and that the foregoing pages constitute a true and accurate transcript of said Hearing.

I do further certify that I am not of counsel for, or in the employment of either of the parties to this action, nor am I interested in the results of this action.

IN WITNESS WHEREOF, I have hereunto subscribed my name this 30th day of July, 2019.

Linda S. Garrett

Linda S. Garrett, CCR

Notary Public No. 19971700150