PLACE: Dobbs Building, Raleigh, North Carolina
DATE: September 28, 2022
DOCKET NO.: E-100, Sub 179
TIME IN SESSION: 9:00 A.M. TO 12:32 P.M.
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC, and
Duke Energy Carolinas, LLC,
2022 Biennial Integrated Resource Plans
and Carbon Plan

VOLUME 28

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IDENTIFIED/ADMITTED

P R O C E E D I N G S

CHAIR MITCHELL: Let's go on the record, please. We will resume with questions on Commissioner's questions for this panel. Let's -- let me see who has questions for the panel based on Commissioner's questions. All right. Why don't we do this? Ms. Cress, do you have questions beyond the information you seek to introduce, the confidential information?

MS. CRESS: I do.

CHAIR MITCHELL: Okay.

MS. CRESS: Just a few.

CHAIR MITCHELL: Okay. So I think let's do CCEBA first, then CIGFUR, then Walmart, then Public Staff. Anyone else on this side of the room have questions? Okay. Ms. Force, questions?

MS. FORCE: No questions.

CHAIR MITCHELL: Okay. Because I was going to -- I saw -- I remember your hand from yesterday, and so you would go first if you had questions.

MS. FORCE: Thank you. I appreciate it, but we have no questions.

CHAIR MITCHELL: Okay. Okay. All right. And then obviously you all will get an opportunity as well. Okay. Go ahead, Mr. Burns.

MR. BURNS: Thank you, Chair Mitchell.

BOBBY McMURRY, MICHAEL QUINTO,
GLEN SNIDER, AND MATTHEW KALEMBA;

Having been previously sworn,
Testified as follows:

EXAMINATION BY MR. BURNS:

Q Good morning, gentlemen. I have the honor of going first to talk to you, and I'm going to -- I have a few questions on what the Commissioners covered yesterday. And I'll tell you in advance there's two real topics, so once we get through the second one, I'll pass it off to Ms. Cress.

Commissioner Brown-Bland asked you at the beginning of the Commissioners' panel yesterday if you had any reaction to Mr. Norris' testimony about the Company having lumped various storage technologies together and not evaluated them separately and how that affected the value of various technologies. Do you recall that question?

A (Mr. Snider) I do.

Q You responded to Commissioner Brown-Bland that you wouldn't say you had lumped technologies together, but you would not call storage a mature technology and there were risks because only 6 GW in the entire United

States of battery storage had been installed. Do you recall that answer?

A I do.

Q Later, Commissioner Duffley asked you to clarify your statement that there were "billions of dollars of investment that have a lot of risk attached to them that have not been spoken about in the last few weeks." Do you recall that question?

A I wouldn't say there -- that I called it quite that way, but I do remember saying, yes, that there are -- billions of dollars invested also have risk and that all technologies have risk and we just did not focus on those.

Q And then Chair Mitchell asked her final question yesterday asking if you had anything to answer any other questions that had been asked to other witnesses. Do you recall that one?

A I do recall that.

Q You responded to both of those questions, again, testifying that the risk associated with storage was not being adequately appreciated before the Panel. Do you recall that?

A I do say that we spent an inordinate amount of time talking about the risk of gas technologies and a fairly limited amount of time, if any, in this three weeks talking about the risks of all the other technologies such as storage. Yes. I remember that.

Q And then in reference to storage you stated again that it wasn't a mature technology and that there was only 6 GW of storage online. Do you recall that?

A I do recall that.

Q Are you familiar with the 2022 NREL report Storage Futures Study: Key Learnings for the Coming Decades that was attached to CCEBA's comments as Exhibit I?

A Vaguely.

Q I can hand you a copy of it if you don't mind. It's already in evidence.

MR. BURNS: May I approach?

CHAIR MITCHELL: You may.

Q Here you are. I'm going to refer to that page if you'd like to look at the document.

MR. BREITSCHWERDT: And Mr. Burns, just so I've got the right --

MR. BURNS: Yeah.

MR. BREITSCHWERDT: -- citation, this is Mr. DiFelice's testimony or this is the prior comments and --

MR. BURNS: It's the prior comments filed by

CCEBA. It was Exhibit I to those comments. And it's --

MR. BREITSCHWERDT: I'll track that down. Thank you.

MR. BURNS: It is a 2022 report called Storage Futures Study: Key Learnings for the Coming Decades.

MR. BREITSCHWERDT: Thank you.

Q Are you with me, sir?

A I am with you.

Q Okay. Great. I handed you what is turned to page 7 of the report which is page 16 of the document as a PDF. But it's -- in the lower left-hand corner it's page 7 and it's -- at the top of it, it says Key Learning 3. Are you with me there?

A I -- Key Learning 3. I'm sorry. Where are we? Yeah. I'm with you. I'm on that page. Sorry.

Q "The ability of storage to provide firm capacity is a primary driver of cost competitive deployment," correct?

A That is correct.

Q Okay.

MS. CRESS: Objection. This is not relevant to Commissioner questions that were asked yesterday. He is attempting to rehabilitate a witness that's no longer on the stand.

MR. BURNS: I am using a document referred to in prior testimony to establish that storage is a mature technology. That's where I'm going.

CHAIR MITCHELL: Overruled.

Q All right. Do you see that the NREL's author state there under Firm Capacity, it's a little blue heading, Firm Capacity, "Storage provides firm capacity, the ability to meet demand during system peak and replace conventional generators such as gas turbines." Do you see that statement?

A I see that statement from NREL.

Q Okay. It also states that "Storage can provide energy time shifting," and so one of the blue headers Operating Reserves and Avoided Transmission, and can in the third column "provide multiple services either simultaneously or at different times, often referred to as value stacking." Do you agree with those statements?

A If placed properly and evaluated properly, yes. We support storage as part of our broad mix of resources that will be part of this energy transition.

Q I'm glad you went there because it's where I was going. In fact, Duke counts on the continued development of battery storage in all of the portfolios presented as part of its carbon plan and the supplemental portfolios, doesn’t it?

A Yes.

Q And Duke’s Near-Term Execution Plan calls for procurement of 1600 MW of battery storage through 2024, correct?

A Yes, it does.

Q And the way you frame -- the way Duke frames it is 600 MW of solar plus storage and 1000 of standalone; is that right?

A Yes.

Q So that’s 1.6 GW of battery storage in Duke’s plan, about one-third of the total amount of battery storage you testified was distributed nationwide currently?

A Yes. I said that a concentration of risk, if you had no gas and wanted to double or triple that, would be concentrating the risk. And as I said, all these technologies have both cost and benefits, and I think it’s a matter of sharing the risk across a suite of technologies and not focusing on a single one. So yes, I think we did not say storage does not have promise; it just needs to be looked at, both its benefits and its risks accordingly, along with all the other technologies.

But yes, we -- I’m with you, Mr. Burns, and we

think storage will play a part of the energy transition.
Q And the real question between Duke and Intervenors is not -- is really how much and by when, right?
A How much, how fast, and -- and many other aspects. What configuration, where it’s sited, how to maximize the value, but yes.
Q But to be clear, none of Duke’s portfolios would come close to achieving the carbon dioxide reductions required in House Bill 951 without the role of battery storage?
A Battery plays a role. You know, the qualifier of how close, I don’t know that I’ve done the analysis without batteries to see how many tons of carbon that contributes, so I will say it is integral in all -- of the 12 portfolios, all had storage as part of those 12 portfolios.
Q Thank you. That’s the first topic. Secondly, Commissioner Brown-Bland also asked you as a panel if you recalled witness DiFelice’s testimony about double counting and depth of discharge. Mr. Kalemba, I believe you responded to that one. Do you recall that?
A (Mr. Kalemba) I do.
Q You stated that you remembered the written

testimony and that you disagreed with Dr. DiFelice; is that right?
A That’s right.
Q You said that when you billed the cost from the bottom up, you account for the depth of discharge amount that you have to overbuild the battery. Do you recall that testimony?
A I do.
Q On page 19 of his testimony, witness DiFelice quotes page 7 of Appendix K of the carbon plan. Do you have page 7 of Appendix K?
A Yes.
A (Mr. Snider) Give us a moment.
Q Sure. Go ahead. Take your time.
A (Mr. Kalemba) I see it.
Q Do you see the header Depth of Discharge?
A I do.
Q “The cost of the battery storage assets in the carbon plan assumes that the asset is designed to include a 90 percent depth of discharge constraint. This means that if a battery is designed with 100 MWh of usable energy, the total energy of the battery would be 111.1 MWh. The depth of discharge constraint is included to reflect requirements of the original equipment

manufacturer to maintain the warranty on most batteries." Did I read that correctly?

A You did.

Q Now, does that mean that they're -- that you model that battery as being purchased as 111.1 MWh battery?

A The full usable, full capacity is 111 MWh, so there's enough battery storage to account for 111.

Q So for 90 percent of that discharge to be 100 MW; is that right?

A That's correct.

Q Now, witness DiFelice testified that original equipment manufacturers and energy storage integrators already factor in this depth of discharge constraint when pricing. Do you agree or disagree with that statement?

A I'm sure it's in the pricing, yeah.

Q Okay. And what -- what cost projection -- well, let me restate that. Duke Energy used the BloombergNEF cost projections for usable kilowatt hours of battery storage, didn't they?

A I'm not sure. The Bloomberg? I'm --

Q Okay.

A Can you ask that again?

Q Well, if the -- if the assumptions, if the

BloombergNEF cost assumptions were used, as referenced in Figure 2-4, Key Base Assumptions of the Carbon Plan, if those modeled costs were the modeled costs used for storage, it already incorporates that reduction in depth of discharge, doesn't it?

A We didn't use the Bloomberg cost for storage. If you can point me to where I state that, that would be helpful.

Q Sure. I believe in Chapter -- Chapter -- if you'll look at Figure 2-4 of the Carbon Plan. Do you have that?

A Figure 2-4, is that what you said?

Q Yes. Key Base Assumptions.

A I'm getting there.

Q Sure.

A I'm there.

Q All right. Key Base Assumptions for Selectable Supply Side Resources?

A Yes. I see that.

Q And it drops a footnote 11, National Renewable Energy Laboratory 2021 Annual Technology Baseline. Do you see that?

A I do.

Q The 2021 update, are you aware that it utilizes

the BloombergNEF cost projections?
A I'm not aware that -- that they use the Bloomberg, but --
Q Okay.
A -- that's --
Q And witness DiFelice testified that they did, but that would be an area that you don't -- you don't know --
A Yeah.
Q -- and agree with?
A Subject to check, I'll agree with that, sir.
Q All right. And if, in fact, those cost projections already incorporate the depth of discharge, then accounting for a larger size battery, as you did your build up from the bottom, would actually count that amount twice, wouldn't it, the extra amount?
A No. I mean, we're within 1 percent of those -- of the NREL values that include the depth of discharge. That's already accounted for, so we're -- I think we're fully aligned with those costs.
A (Mr. Snider) And I would just respond as well that we say in our direct testimony on page 192, Figure 17, we show CPSA, NCSEA, and Tech Customers, and on batteries we're slightly lower than Tech, very close or

maybe a little lower than CPSA, and NCSEA is 20 percent lower than the three of us. So, you know, we are not an outlier in this case, anyway, on the cost of batteries. We have two of the other Intervenors that say we're -- they're in agreement with us, and it's one Intervenor that's 20 percent lower.

Q Understood. Thank you for that response.

MR. BURNS: If you'll give me just one moment, Madam Chair, I think I may be complete there, but I want to check one thing.

Q To go back to my -- the first question from Commissioner Brown-Bland. In response to that first question, you had -- you made a statement that we gave free transmission to paired storage. Do you recall that? That was in the lumping question.

A Yeah. We did not increase the proxy cost of the transmission when we added SPS, solar plus storage, at the same proxy cost as standalone such that we didn't include an incremental cost. And I think my statement was that that may very well be the case if, subject to Mr. Roberts correcting me, if you add it without charging from the grid, which we assumed in the model, but if you did charge from the grid, we would need to relook at that analysis because you would then need to be able to deliver solar -- or energy to the solar facilities when the solar wasn't there so that you could charge the battery. And we did not study that in these proxy costs that we came up with, so we didn't increase the cost of solar plus storage in our proxy transmission.

Q Sure. But when you said -- I just wanted to clarify for the record, when you said "free transmission," you didn't give free transmission to storage. It's storage and solar on a solar plus storage system use the same point of interconnection, so the transmission improvements would be the same, correct, or the cost of transmission?

A Subject to Mr. Roberts, again, it's the -- solar is the -- the battery is going to change the profile of that output, and I do think there may be -- and, again, I'll ask Mr. Roberts to follow up with me here, but you will change the profile. There is a potential you could even have additional transmission because of the change in the profile. So, for example, solar doesn't provide energy on a winter morning, but solar plus storage will. I'm not a hundred percent sure that it was studied that way. We needed the original standalone. So we did not assume an increased cost. There may be a potential that there's an increase. We didn't assume it in our modeling and we certainly didn't assume there was a charging cost in it. So we were to the benefit of solar plus storage is my point, you know, when it comes to the ascription of transmission cost.

Q And my question wasn't a way of eliciting a disagreement. I just wanted to clarify the record. I appreciate your response.

A Yeah.

MR. BURNS: And that's all my questions. Thank you.

EXAMINATION BY MS. CRESS:

Q Good morning, gentlemen. You heard some questions yesterday from Commissioner Hughes regarding future cost, cost assumptions, and modeling net present value revenue requirement impacts. Do you recall those questions?

A (Snider) I do.

Q As a follow-up to that question, I just want to ask whether you modeled any sensitivities or scenarios wherein future cost estimates or net present value revenue requirement impacts were constrained?

A I'm not sure I understand the question. Did we model scenarios where revenue requirements were constrained?

Q Correct.
A Is that your --
Q Or were they unrestrained?
A They were --
Q Unconstrained.
A It's an output. We didn't say we're going to limit a PVRR at a certain point. We did not constrain whatever the PV--- whatever the PVRR was, present value of revenue requirements was, it was. We did not model any scenarios where we put a cap on that.
Q Thank you.
MS. CRESS: That's my only question, but I do -- Chair Mitchell, I had discussed with counsel for Duke before this morning's session that there's a line of questioning that would elicit confidential information, and in lieu of asking that line of questioning, I believe counsel for Duke has agreed to stipulate that an exhibit -- a confidential exhibit be identified, marked, and entered into the record.
MR. BREITSCHWERDT: Duke Energy agrees with that approach if acceptable to the Commission.
CHAIR MITCHELL: All right. You may proceed.
MS. CRESS: Thank you. At this time CIGFUR II and III would like to introduce and move into the record

CIGFUR II and III Modeling Panel Rebuttal Confidential Commissioners' Questions Exhibit Number 1.

CHAIR MITCHELL: So we'll identify the document as CIGFUR II and III Modeling Panel Rebuttal Commissioners' Questions Confidential Exhibit Number 1.

MS. CRESS: Thank you, Chair Mitchell.

(Whereupon, CIGFUR II and III Modeling Panel Rebuttal Commissioners' Questions Confidential Exhibit Number 1 was marked for identification.)

CHAIR MITCHELL: All right. Walmart, you may proceed.

MS. GRUNDMANN: Thank you, Chair Mitchell.

EXAMINATION BY MS. GRUNDMANN:

Q Good morning again, gentlemen. I'll give you a second to get that exhibit. I would like to follow up on Commissioner Clodfelter's questions with respect to gas, our favorite topic. I just have -- Mr. Snider, I think these are probably questions for you, and it goes back to the discussion of the sort of three alternative supply scenarios. I want to try to better understand, to the extent you can, I'm trying to understand timing.

So yesterday in response to questions from Mr.

Clodfelter, you indicated that the completion of MVP was the Company's preferred method to obtain additional natural gas supply, correct?

A (Mr. Snider) Yes.

Q And so my understanding, and please correct me if I'm wrong because in some ways I was a little confused, once MVP is built, the Company would actually need an additional project modeled after what Piedmont Gas successfully did to access natural gas through MVP. Was that your testimony?

A No.

Q Okay. Can you explain that to me?

A No. We would have -- the first phase that we spoke about was providing gas to our existing -- additional gas to Zone 5 that would be available to improve the liquidity in Zone 5 and provide upstream gas for our existing combined cycle fleet, and we have -- we would not need that type of project for that.

Q But just to clarify, though, for that sort of what you call the first phase, you would envision that that would come from the completion of the MVP project?

A That is, yes.

Q Under the Company's first preferred scenario.

A Yes.

Q And then you also contemplated some sort of a buildout and an upgrade of MVP at some point thereafter; is that correct?
A Yeah. That would be a potential to get incremental Zone 5 gas.
Q And so by “incremental,” you mean not firm?
A No. I mean incremental to the first 525.
Q But you would envision that that would all be firm supply?
A Yes.
Q Okay. Okay. So then second option -- and I’m going to come back to MVP, but then second option if MVP doesn’t work out is to attempt to do something similar with transporting from the south on Transco.
A Or any pipeline from the south --
Q Okay.
A -- but yes.
Q But same premise, some updated or some upgrades necessary to provide you that incremental additional firm?
A That is correct.
Q Okay. So then going back to MVP, you’re aware, are you not, that FERC extended the construction permit through October ‘26 -- October 2026, but that MVP has

indicated it's hopeful that it will complete construction by middle to end of next year?
A I am familiar with that.
Q Okay. And are you aware that in response to that ruling from FERC, that MVP indicated that one of the reasons it was pleased by that ruling is that the capacity for MVP remains fully subscribed under long-term binding contracts? Have you seen that phraseology from MVP?
A Yeah. I understand that.
Q Okay. So yesterday -- does that indicate, based on the information you gave yesterday, that Duke is one of those parties that would --
MR. BREITSCHWERDT: Chair Mitchell?
MS. GRUNDMANN: Oh, I apologize. I don't -- I didn't mean to go into confidential information.
MR. BREITSCHWERDT: Yeah. To the extent we're going to go any further, I think we would need to go into confidential session.
MS. GRUNDMANN: I have no desire to go into confidential session. Let me move on.
Q Has the Company done any analysis or sort of looking at the timing of when it would decide to transition from its pursuit of its preferred path with

MVP to the alternative pathway through some southern transport with Transco or some other pipeline?

A Yeah. I think we discuss a pivot that would take place if the northern route was no longer an option.

Q My question is when would you make that decision? Would you be willing to go until October 2026 if MVP wasn't built and then say that's the time to pivot, or have you considered some earlier pivot date?

A I think it'll depend on how the marketplace unfolds over the next couple years with respect to pipeline.

Q So it sounds like at this point in time you haven't identified some if not built by "x" date, we pivot. It's going to be a --

A It's going to be -- yeah. The dynamics will play out and there will be a decision at a future point.

Q Okay. So then you pivot to some southern pipeline option. Do you have any idea or estimate -- and understand, I remember yesterday you sort of indicated that, you know, you've got some familiarity, but some of this really isn't within the scope, so please let me know if you're not the right person -- but how long it would take for a southern pipeline option to perform the upgrades that would be necessary to bring the gas that you would need?

MR. BREITSCHWERDT: Chair Mitchell, I don't know where the line is of what needs to go into confidential session, but I feel like this is also pushing on that in terms of what a southern pipeline project would need to -- the timing of when that would need to go into service, so I'm -- I don't know. Mr. Snider, I guess I would just remind you that there is a line and just want to make sure you're only answering questions that are acceptable to be answered in public, and if you're not comfortable answering a question, we can either go into confidential session or move on if that's appropriate.

A Let me try a high-level answer that would not -- I think it will be dependent upon the nature of that, you know, to the extent -- try and do as much brownfield as possible, and the nature of that project would determine the timeline, and I think that would be about all I want to sort of say on that. Once you've pivoted, then it would be -- the nature and scope of that pivot project that would determine that timeline.

Q And so if I -- I'm going to pose a question and you let me know if it's something that would implicate confidential information and we can move on. So can you sort of -- it sounds like there's sort of a range of options depending on how the projects go. Are you able, without implicating confidential information, to provide me a bracket of how long a project could take from the shortest amount of time to potentially the longest high level?

A Yeah. I would -- and, again, subject to check, because I am -- this is outside sort of the scope of my direct area of responsibility, but it could be, you know, a couple of years to multiple years, three, four, beyond. So I would think it's not a matter of months; it is years, you know. And I'm going to give you a broad range of, you know, two to four years, let's say, as a very, very broad range.

Q Yeah. That's all the more detail I was looking for.

MS. GRUNDMANN: Thank you, Mr. Snider. Those are all the questions that I have.

EXAMINATION BY MS. EDMONDSON:

Q Good morning, gentlemen. Lucy Edmondson from the Public Staff. You'll be excited to know I'm not going to ask any questions about natural gas. So first one clarifying question. I believe -- I think Mr. Snider indicated to the Chair that the near-term plans for all six portfolios were the same?

A (Mr. Snider) I said they're generally supported. Actually, 12 portfolios if you look at the alternates. So yeah, I think they're generally supported by all of the analysis.

Q Isn't it true that under Portfolios P5 and P6 they do not economically set -- select offshore wind until after 2040?

A The near-term action plans call for the -- just the development work, so it's not the in service of offshore wind. And I think all of the portfolios show a need for offshore win, as Mr. McMurry and others have testified. You know, we're going to need these. It's a matter of when and not if. You're going to need this diverse array.

And I think I testified that P1 and 2 economically select offshore wind. P5 was a stress on P1 and 2, so it put in transmission hurdle rates. It had a different gas assumption. It had, you know, different battery optimization assumptions that can influence whether or not offshore wind -- the timing off offshore wind, so it was not in that stress test. It was not selected, but P1 and 2 did select 800 MW of offshore wind in P1 and then there was 1600 in P2 that were in the nearer term. So you're correct. That stress test in 5 and 6 did not have it, but I view that as a stress and not as a primary.

Q And development of offshore wind, would you agree it takes generally somewhere 10 years or so; is that --

A Yeah. That's what I understood from the Long Lead-Time Panel, so I'm going to sort of leave it there and let them opine further on that.

Q Thank you. Okay. Three modeling questions. I'm not sure who gets these. So Commissioner Hughes was discussing with you of transparency in the modeling and whether the post-processing tools for calculating PVRR were shared with Intervenors.

A I remember that.

Q You've testified before that Duke received a significant quantity of discovery in this proceeding, correct?

A That's a fair assessment.

Q And would you agree that many of these data requests were related to modeling inputs, outputs, PVRR calculations, and general modeling questions?

A Yes. They were.

Q So would you agree that the sharing of workpapers, calculations, methodologies that are directly involved in calculating model inputs, such as the real levelized fixed charge rate and analysis of model outputs such as PVRR, would cut down on the discovery?

A Yeah. We have been talking about ways in this hearing to expedite that and, you know, the only thing I would add to that is I think we need to think of that also as a two-way street. So the same level of transparency that we're trying to provide, we would just ask that however we work future processes it is reciprocal in nature such that, you know, we don't have two weeks while someone else has three months with the same level of data.

So subject to that, you know, trying to be a little bit more reciprocal in nature and symmetric in the sharing of data and tools and underlying, I think there are ways to -- we could provide that. Some of these we put all the data sets up there. We could probably put additional -- some additional information right when we file, and I think that would help.

Q Great. Thank you. Commissioner Hughes asked you about the use of a typical day representation of load in the capacity expansion model, and you responded how that biases resource selection towards short-term batteries.

A It does have a bias towards overvaluing batteries. Yes. I remember that conversation.

Q Could this issue potentially be addressed in the capacity expansion models by changing the model intervals to provide more granularity in the daytime rather than using six equal intervals of four hours each?

A No. I mean, you’re still -- it goes well beyond that, because you still have to maintain peak and mins, as it was explained, plus energy, so that’s stretching. So I’m not saying the intervals, but there are thing -- I’m not saying that there aren’t improvements that could be made, but at the end of the day, the screening model is always going to be a more simplified model. And I think there are enhancements that will get you closer so you don’t need to take -- you won’t have as many production cost 8760 differences, so trying to get those two to get closer is something we’re going to strive for. But recognizing the purpose and, again, we talked about using the right tool to answer the right question at screening, you’re screening tens of thousands of options, so you have to use simplification.

Production cost you’re using one portfolio 8760, so I do think there’s improvements that can be made. I think the vendor is looking into it, the industry is looking into it, we're looking into it. But at the end of the day there's still going to be a need to go to more detailed production cost modeling to verify and fine tune the results you get out of the screening model.

Q You just mentioned some enhancements. Could you expand on what you mean by that?

A I think enhancements in how you -- how you -- with the recognition that time shifting is now one of the key aspects, as opposed to just meeting energy and peaks, anything we can do to improve at the screening level a better representation of the time, not having such a distortion in the peaks to the mins would be beneficial and -- but at the end of the day, with storage, whenever you take a simplification, what I'm saying is, you know, its day-in/day-out value is going to depend on an 8760, which is just not possible at the screening. So I think limiting that distortion, getting the time steps, looking at different options for those can start to move you in the right direction.

Q Okay. I want to -- Ms. Grundmann is going to pass out an exhibit for me. All right. We already discussed this morning some of the lumping of all new technologies that you discussed with Commissioner Brown-Bland. And then Commissioner Hughes also asked you about typical day representation, and you talked about the solar plus storage dispatch and how these resources were modeled as DC coupled resources unable to charge from the grid. Do you recall that?

A Yeah.

Q Have you seen this document before or any information about this new version of EnCompass 6.2?

A I'm going to allow -- Mr. McMurry is --

A (Mr. McMurry) Sure. This was released, I think, last week, so I know some of the folks in my group, they reviewed it. We're just now uploading it into our developmental server. Often before we really -- you know, we test everything that's in the notes before we say it's ready for production, so we're in that testing phase right now. But I knew that 6.2 has been released, and we're in the testing phase right now.

Q And would you agree that it represents that this would allow DC coupled solar plus storage to charge from the grid, according -- that's what the release indicates?

A I was looking for an opportunity yesterday to bring that up when it was discussed, but that is an enhanced feature that they are now offering. But as I stated, we have not tested it yet, and I think we'll get there. I mean, I'm not trying to backpedal at all, but this is a -- this is the first time we've had a tool that would allow us to access that.

Q All right. Well, how long will it take to test that before you will know whether you will be able to use that functionality in future carbon plans?

A I've got several folks that are -- several people within my group that are supporting this hearing, so that's slowing down the testing somewhat, but typically a couple weeks.

Q Okay. Great. That's all I have. Thank you.

A All right.

A (Mr. Snider) Thank you.

MR. BREITSCHWERDT: No questions. Thank you.

CHAIR MITCHELL: All right. With that, we've come to end of cross examination of this Panel, so you all may step down. Thank you very much for your testimony over the past two days.

CHAIR MITCHELL: I'll take motions. And Duke, your witnesses are excused.

MR. BREITSCHWERDT: Thank you, Chair Mitchell.

(Witnesses excused.)

MR. BREITSCHWERDT: The Company would move the Modeling Panel's Rebuttal Exhibits into the record. I think there were three.

CHAIR MITCHELL: All right. Hearing no objection, the motion is allowed.

(Whereupon, Modeling and Near-Term Actions Panel Rebuttal Exhibits 1, 2, 3, and 4 were admitted into evidence. Exhibits 2, 3, and 4 were filed under seal.)

MS. CRESS: Chair Mitchell, CIGFUR II and III would move that Modeling Panel Rebuttal Cross Examination Confidential Exhibits 1, 2, and 3 be entered into the record as well as CIGFUR II and III Modeling Panel Rebuttal Commissioners' Questions Confidential Exhibit 1.

CHAIR MITCHELL: Motion is allowed.

MS. CRESS: Thank you.

(Whereupon, CIGFUR II and III Modeling Panel Cross Examination Confidential Exhibits 1, 2, and 3, and CIGFUR II and III Modeling Panel Rebuttal Commissioners' Questions Confidential Exhibit 1 were admitted into evidence and were filed under seal.)

MR. BURNS: CCEBA would move the admission into evidence of CCEBA Modeling Panel Rebuttal Confidential Cross Examination Exhibit 1.

CHAIR MITCHELL: And that motion is allowed.

(CCEBA Modeling Panel Rebuttal Confidential Cross Examination Exhibit 1 was admitted into evidence and was filed under seal.)

MS. EDMONDSON: And I did not have the exhibit marked, and I apologize. If the Anchor Power Solutions Release 6.2 could be marked as Public Staff Modeling Panel Rebuttal Commission Questions Exhibit 1, we would ask that that be entered into the record.

CHAIR MITCHELL: All right. The document will be marked as Public Staff Modeling Panel Rebuttal Commission Questions Exhibit 1. Hearing no objection to your motion, the exhibit will be admitted into evidence.

(Whereupon, Public Staff Modeling Panel Rebuttal Commission Questions Exhibit 1 was marked for identification and admitted into evidence.)

MS. EDMONDSON: And may I ask one clarifying question?

CHAIR MITCHELL: You may.

MS. EDMONDSON: So I brought to the attention of witness yesterday the July 28th letter that was filed in this docket, and I did not enter it as an exhibit because it's part of the record. Is that appropriate or should that be entered into the record?

CHAIR MITCHELL: Abundance of caution, the Commission will take Judicial Notice of the letter filed in this docket on July 28th by DEC and DEP.

MS. EDMONDSON: All right. Thank you so much.

MS. NICHOLS: Good morning. Lauren Nichols on behalf of Duke Energy. We call Laura Bateman to the stand.

CHAIR MITCHELL: All right. Good morning, Ms. Bateman. We will get you sworn in again, please, ma'am.

LAURA BATEMAN; Having been duly sworn,
Testified as follows:

DIRECT EXAMINATION BY MS. NICHOLS:

Q Ms. -- I'll wait till you're situated. Ms. Bateman, are you the same Laura Bateman that previously appeared in this proceeding on September 19th with Mr. Nelson Peeler as part of the Company's Utility Operations Panel in our direct case?

A Yes.

Q Okay. And did you cause to be prefiled in this docket rebuttal testimony consisting of 11 pages?

A Yes.

Q Do you have any additions or changes or corrections to your rebuttal testimony at this time?

A No, I do not.

Q If I were to ask you the same questions today that appear in your prefiled rebuttal testimony, would your answers be the same?

A Yes.

Q Does your rebuttal testimony contain any confidential information?

A No.

MS. NICHOLS: Chair Mitchell, I would ask that Ms. Bateman’s rebuttal testimony be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. The motion is allowed.

(Whereupon, the prefiled rebuttal testimony of Laura Bateman was copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	**REBUTTAL TESTIMONY OF**
Duke Energy Progress, LLC, and	)	**LAURA BATEMAN ON**
Duke Energy Carolinas, LLC, 2022	)	**BEHALF OF DUKE ENERGY**
Biennial Integrated Resource Plan	)	**CAROLINAS, LLC AND DUKE**
And Carbon Plan	)	**ENERGY PROGRESS, LLC**

I. INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Laura A. Bateman, I am the Vice President of Carolinas Rates and Regulatory Strategy, and my business address is 411 Fayetteville Street, Raleigh, North Carolina, 27601. I am providing testimony on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy.)

Q. ARE YOU THE SAME LAURA A. BATEMAN THAT FILED DIRECT TESTIMONY IN THIS CASE AS PART OF CAROLINAS UTILITIES OPERATIONS PANEL?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the testimony of Public Staff witness James McLawhorn, Carolina Industrial Group for Fair Utility Rates ("CIGFUR") witnesses Brad Muller and Michael P. Gorman, and Carolina Utilities Customer Association, Inc. ("CUCA") witness Kevin W. O'Donnell regarding several rate-related issues. First, I explain why no interim cost allocation methods, as proposed by witness McLawhorn, are needed prior to the Companies' targeted date for a merger of the DEC and DEP utilities. Second, I explain why "all-in" customer rate projections, as requested by witnesses McLawhorn, Muller, Gorman, and O'Donnell, are neither feasible nor necessary in this proceeding. Finally, I address the concern raised by witnesses Muller and Gorman regarding how costs should be allocated in the event the Public Service Commission of South Carolina ("PSCSC") makes different decisions from this Commission on Carbon Plan investments.

II. MERGER AND PLANS FOR ADDRESSING RATE DIFFERENCES BETWEEN DEC AND DEP

Q. PLEASE REITERATE THE COMPANIES' POSITION WITH RESPECT TO A POTENTIAL MERGER.

A. The Companies agree with the Public Staff that a merger of DEP and DEC would be the most straightforward solution to resolving both existing and potential future rate differences. If stakeholders agree upon and regulators approve an equitable approach to a merger, once accomplished, it would allocate the Carbon Plan costs to customers of both legacy utilities.

Q. IN YOUR DIRECT TESTIMONY, YOU DESCRIBED THE GENERAL REASONS FOR THE CURRENT DIFFERENCE IN RETAIL RATES BETWEEN DEC AND DEP. PLEASE ELABORATE ON DRIVERS OF THE HISTORIC RATE DIFFERENCE.

A. As Public Staff Witness McLawhorn states in his testimony:

> DEC and DEP are separate utilities, each possessing a unique service territory, customer base, and generation, transmission, and distribution assets. Because rates are set based upon average cost of service, and given the differences listed above, it is not surprising that some rate differentials exist, and in fact they have existed since before the corporate

> merger of Duke Energy Corporation and Progress Energy Corporation in 2012.[1]

One of the primary reasons for this differential is fuel costs. DEC has a higher percentage of low fuel cost nuclear generation than DEP has. Between 2015 and 2021, the average percent of DEC's MWh generation from nuclear facilities was 61%. For DEP, this number was only 47%. In addition, due to its geographic location, DEP has higher fuel transportation costs than DEC does. In the fuel case filed in 2022, Docket No. E-2, Sub 1292, DEP's average price of natural gas purchased was $5.44 per MMBtu, compared to DEC's average price of gas purchased reported in the 2022 DEC fuel filing, Docket E-7, Sub 1263 of $4.22 per MMBtu. Similarly, DEP's average delivered cost of coal was $84.26 per ton compared to DEC's cost of $78.22 per ton. These fuel differentials have led to DEP having higher avoided cost rates than DEC, which has contributed to DEP's higher volume and cost of PURPA contracts, and to a higher DSM/EE rate (more cost-effective programs). As Mr. McLawhorn notes, these types of differences can be expected based on unique characteristics of each utility, and while DEP's rates are higher than DEC's, they are still below the national average, meaning they are below the rates of many other utilities across the country.

[1] Public Staff McLawhorn Direct at 5.

Q. PUBLIC STAFF WITNESS MCLAWHORN ARGUES THAT "OVER A DECADE HAS PASSED WITHOUT MEANINGFUL PROGRESS" TOWARDS A MERGER BETWEEN DEC AND DEP.[2] DO YOU AGREE?

A. No. Duke Energy has accomplished significant integration between DEC and DEP over the last 10 years. We have standardized processes and moved to common systems, tools, and platforms across various functions. For example, my team has implemented a common tool and reporting format for our cost-of-service studies. Accounting has implemented common code block and accounting tools, and operations teams have moved to common work management tools. The Companies also recently implemented "One face to the market," a combined approach to fuel procurement for DEC and DEP to lower costs for both utilities, approved by this Commission in Dockets E-2, Sub 1282 and E-7, Sub 1258. Finally, we have implemented a modern and standardized customer and billing system for DEP and DEC, a multi-year implementation effort that was just completed at the end of 2021. This was a critical step to facilitate the merger of the utilities. Thus, now is the appropriate time to develop the plan to merge the utilities.

[2] *Id*. at 14.

Q. DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATION THAT THE COMMISSION REQUIRE THE COMPANIES TO DEVELOP A PLAN FOR ALLOCATING CARBON PLAN COSTS BETWEEN DEC AND DEP UNTIL THE COMPANIES MERGE?

A. No. Developing a plan for allocating Carbon Plan costs between DEC and DEP is not necessary given the current projections of the timing of Carbon Plan investments and the timing of the merger. The projected impact of the Carbon Plan investments on current rate differences prior to the targeted merger is minimal to non-existent (depending on the portfolio assumed). Therefore, the Companies believe that attention and resources should be devoted towards pursuing a potential merger rather than developing a "stop-gap" method to cost allocation that is not needed at this time.

As discussed in my direct testimony, the Companies suggest a timeline for merging DEC and DEP by the end of 2026, and the revenue requirements for the proposed Carbon Plan investments prior to 2027 are proportionally divided between DEC and DEP. As shown in the Table, below, in only two of the six portfolios are the $/MWh revenue requirements through 2026 greater for DEP than for DEC using the existing direct assignment approach, and in one of those portfolios, the difference is only eight cents. Thus, the Carbon Plan investments are not materially, and in most cases not at all, widening the rate differential through 2026.

Cumulative Retail Revenue Requirement through 2026 ($/MWh)

	P1	P2	P3	P4	P5	P6
	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh	$/MWh
DEC	1.36	1.48	1.46	1.26	1.88	1.60
DEP	1.33	0.42	1.54	1.81	1.29	1.27

If a merger is not achievable, then the Companies will look to implement the alternative methodologies outlined in my direct testimony post-2026.

III. BILL IMPACT CALCULATIONS

Q. PLEASE EXPLAIN HOW THE CUSTOMER BILL IMPACTS INCLUDED IN THE CARBON PLAN WERE CALCULATED.

A. My team took the capital and production costs from the Modeling team to calculate a revenue requirement and the projected rate impacts in 2030 and 2035. The inputs from the Modeling team excluded costs that were common to all portfolios. In determining the rate impacts, we did not try to model rate case timing or specific cost recovery mechanisms. Instead, we assumed "perfect rate-making," which means we assumed the costs were reflected in customers' rates concurrent with when the revenue requirements are incurred (a.k.a. no regulatory lag). This is fairly typical in long-term projections. Then, we layered in a projection of customer savings that would be realized through securitization.

Q. PLEASE DISCUSS THE POSITION TAKEN BY THE PUBLIC STAFF AND INTERVENORS THAT THE COMPANIES SHOULD PRODUCE ADDITIONAL ANALYSES THAT INCLUDE "ALL-IN" PRESENT VALUE REVENUE REQUIREMENTS ("PVRR") AND BILL IMPACTS.

A. The Companies do not prepare a forecast that includes all costs and revenues that goes out for 10 or 15 years. As background, the Companies' Integrated Resource Plans ("IRPs") have historically shown Present Value of Revenue Requirements ("PVRR") for costs of the resource plan and used this metric as a valuable tool to compare one portfolio to other alternatives. These PVRRs have never included all future revenue requirements of the utility, but only those caused by the resource plans. In the Companies' 2020 IRP, based on feedback from the Public Staff, the Companies, for the first time, included average annual customer rate impacts by 2030 and by 2035. The rate impacts used the same revenue requirement inputs that were used in the PVRRs and should be used in combination with the PVRRs to compare one portfolio to another in terms of cost to customers. The Companies continued this approach in the Carbon Plan. These rate impacts were never intended to try to predict exactly what a customer's all-in rate will be in 10 or 15 years, but instead were meant to be a valuable tool for comparing alternative resource plans.

Dominion Energy North Carolina also produces customer rate impacts in its IRP filings with the Commission, and while these rate impacts include some costs that are common to all plans, they are not all-inclusive projections. In discovery, we asked the Public Staff, CIGFUR and CUCA to provide any such forecasts that they were aware of from other utilities. We did not receive any such forecasts. Even if the Companies were to try to produce such a forecast, it would inevitably be wrong due to the number of different factors that impact rates—interest rates, inflation, fuel costs, government regulations, amortization periods for deferred costs, etc., over many of which the Companies have no or limited control. For example, several witnesses suggest that we include storm securitization impacts. The Companies would have to try to predict the timing and magnitude of future storms, the cost of restoration, and timing of securitization in order to project a future rate impact from storm securitization. This is obviously impossible. For CUCA witness Kevin O'Donnell to suggest that the utility should have a crystal ball to perfectly predict the future for the next 15 years and then be punished with a disallowance if actual costs exceed the projection is completely contrary to the basic principles of utility ratemaking and fairness.

In terms of grid investments, the Companies have worked diligently to develop detailed three-year grid investment plans. DEP presented its plan to the Commission in its July 25, 2022, Technical Conference (Docket E-2, Sub 1300). DEC will be presenting its plan in its Technical Conference (Docket E-7, Sub 1276). The rate impacts of these plans will be included in the Companies' upcoming rate cases. However, the Company does not have similarly detailed grid investment plans for the next 10 or 15 years upon which to base a rate projection, as some interveners seem to assume.

However, even though the Companies are not able to provide the requested "all-in" rate impacts, I continue to think that the rate impacts provided in the Carbon Plan, even with their limitations, are valuable, and when assessed in combination with the PVRRs, are useful in comparing the various portfolios presented.

IV. OPERATING IN A DUAL-STATE SYSTEM AND CONTINUED STATE ALIGNMENT

Q. PLEASE COMMENT ON THE POSITION TAKEN BY CIGFUR THAT NORTH CAROLINA SHOULD BE HELD HARMLESS FROM SOUTH CAROLINA'S "SHARE" OF HB 951 COMPLIANCE COSTS.

A. As discussed in our direct testimony, the Companies believe that the focus of this proceeding should be on the near-term resource development and procurement activities and, as stated in the Carbon Plan, such near-term resources are no-regrets resources. The Carbon Plan (Appendix E Quantitative Analysis) and direct testimony of the Modeling and Near-Term Actions Panel demonstrates that all Carbon Plan and Supplemental Portfolios include adding at least 7,000 MWs of solar to the system to meet the 70% reduction target, and several parties advocate for even greater amounts of solar in the near term. Given this and the fact that North Carolina accounts for approximately 80% of the combined DEC and DEP load, the anticipated solar and solar plus storage sought to be procured prior to the next Carbon Plan update will be needed for North Carolina customers regardless of decisions by the PSCSC.

CIGFUR Witness Gorman makes an assumption that costs will be allocated on a load ratio share methodology and argues that if disallowed by the PSCSC such share should not be recoverable from North Carolina customers.[3] To the extent Mr. Gorman suggests that one jurisdiction should not receive the benefits of resources for which it does not contribute to the costs, I agree. However, the solution to this concern is to use an allocation methodology, such as direct assignment, by which the full benefits of a resource are allocated to the jurisdiction that is assigned the cost of that resource. The Companies anticipate that by 2024 (the date for next biennial Carbon Plan update), there will be more clarity regarding the options available to facilitate continuation of the dual-state system while allowing for differences in state policy.

V. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[3] CIGFUR Gorman Direct Testimony at 6-7; *see also* CIGFUR Muller Direct Testimony at 8-9.

MS. NICHOLS: Ms. Bateman is now available for questions from the parties and the Commission on her rebuttal testimony.

CHAIR MITCHELL: All right. Let me check the latest version. CIGFUR – CIGFUR, you're up first.

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q Good morning, Ms. Bateman.

A Good morning.

Q You previously testified in this docket on September 19th; is that correct?

A Yes.

Q Okay. Are you aware that the Public Service Commission of South Carolina issued an order on September 21st, 2022 in Docket Number 2019-224E and 2019-225E?

A What docket is that?

MS. CRESS: If I could, I'll go ahead and have an exhibit passed around which CIGFUR II and III would request be marked and identified as CIGFUR II and III Bateman Rebuttal Cross Examination Exhibit Number 1.

A No. I am not aware of this Order, and I think I previously testified that I was not involved with this docket.

CHAIR MITCHELL: All right. Let me -- before we continue on, let me identify the document as CIGFUR II and III Bateman Rebuttal Cross Examination Exhibit 1.

MS. CRESS: Okay. Thank you, Chair Mitchell.

(Whereupon, CIGFUR II and III Bateman Rebuttal Cross Examination Exhibit 1 was marked for identification.)

Q So do you have that document in front of you, Ms. Bateman?

A Yes.

Q Could you please turn to page 7?

A Yes.

Q And could you please read for the record the paragraph beginning "In its modified IRP, Duke designated Portfolio C1"?

A And then how far do you want me to read?

Q The whole paragraph, please.

A Okay. "In its modified IRP, Duke designated Portfolio C1 as its preferred portfolio. This portfolio fails to incorporate the Commission required input assumptions as dictated by Order Number 2021-" -- 47 – "447 and reflects an aggressive carbon management strategy that is unsupported by South Carolina law. In fact, the base case A1 portfolio was projected to have a present value revenue requirement of 43.5 billion as opposed to the C1 portfolio which is projected to have a present value revenue requirement of 46.9 billion. Duke modified IRP corrected page 10 of 116. The C1 portfolio requires significant and unsupported deviations from the least-cost planning principles that are relevant in the base case A1 or pursuant to Order Number 2021-447A2. By contrast, in its original IRP Duke“ -- did not specify -- “did not specifically indicate a preferred portfolio plan, but did undertake that its base case Portfolio A1 would incorporate least-cost planning to meet its projected energy needs.”

And I would just add that, you know, I know they’ve been excused now, but the Modeling Panel was involved with this docket in South Carolina, and I think they could provide more context to the Order, whereas I was not involved so I can’t provide that context.

Q Understood. I actually don’t have any other questions. Thank you.

A Okay.

CROSS EXAMINATION BY MR. SCHAUER:

Q Good morning. Craig Schauer on behalf of CUCA. On page 8 of your testimony --

A Of the rebuttal?

Q Yes.

A Okay.
Q Thank you. You address the request of the Public Staff and certain Intervenors to provide an all-in cost calculation.
A Yes.
Q Do you recall that?
A Yes.
Q Did you review the testimony of James McLawhorn of the Public Staff?
A Yes, I did.
Q Do you recall that he noted certain costs were not included in Duke's PVRR calculations?
A Yes. Let me -- do you have the point in his testimony?
Q Do you have a copy of it?
A I do.
Q I believe it's at page 19, lines 11 through 16, is probably what you were thinking of.
A Yes.
Q All right. And some of the examples are transmission costs such as the Red Zone were not included, correct?
A Well, no. So I'm glad you brought that up because I did want to address that. I've been hearing

this theme throughout the hearing, and so I want to be clear on what is included and what's not included in both the PVRR calculations and the rate impacts.

So I believe the Modeling Panel testified that there is a generic transmission cost estimate included in their modeling that approximates the cost of the Red Zone projects. So I would say that those are included, not specifically project by project, but the overall generic cost is included for those.

Q Okay.

A We included projected DSM/EE costs, so those are included. We included projected coal plant securitization savings, so those are included. And various groups at different times led -- you know, testified that these were not included, so I want to make sure that it's clear.

There's an assumption around hydrogen conversion cost that is included. It is not in the bill impacts because it happens in '24 -- in the, you know, later than 2035.

And then I've heard significant questions about a second license renewal, and that is one item that is not included, the costs are not included, but the benefits are not included, either. And for that, the cost savings -- we project that the cost savings will outweigh the costs, so -- in fact, in our upcoming rate cases there will be savings that will be passed on to customers as a result of that assumption of second license renewal in those cases. So there will be a bill decrease that outweighs the increase.

Q And one of the items on page 19 that he lists is cost associated with Duke's grid improvement plan.

A Yes.

Q Those costs were excluded from the PVRR calculations, correct?

A So yes, but I want to address that. So -- and I think I put this in my rebuttal testimony. We have a three-year detailed plan for grid investments, and there is no grid improvement plan anymore. There is just a plan for grid investments and it includes both, you know, base routine work and then work that might be considered more extraordinary.

So we have a three-year detailed plan that we have filed with this Commission for DEP that we will soon file for DEC. And when we file our rate cases in the coming months, there will be rate impacts included associated with that grid improvement plan.

And I think it is important to note that there are some items that are not included in the projections. We don’t have a grid investment plan beyond that three years, a detailed one like the one that we filed here, the one that you can really give good rate projections on. And so any projection would be highly uncertain beyond that period. So when you get to 10, 15 years out, the rate projections would be highly uncertain.

We can’t project -- I think he included storm costs. You know, we can’t project future storm costs. And so there’s a lot of things that aren’t related to the carbon plan, and it would be very difficult for the utility to project those and it -- we wouldn’t be able to project them with any level of certainty.

And I hear Intervenors saying you should provide this, you should provide this, but we have asked and I have asked and tried to find any other utility in the country that provides these type of projections 10, 15 years out, and I have been unable to find that. We asked discovery on it. I talked to some of my peers in other states. I put a question out on the EEI rate subcommittee, you know, looking for anyone that does this, and I haven’t been able to find it, and I think there’s a reason for that.

When you think about the type of modeling and the type of build projections and PVRR that we presented in this carbon plan, it includes a lot of assumptions, and those input assumptions might change over time, but the real value is to compare the portfolios. And I was listening -- I've been listening to this hearing, and I heard NCSEA witness Varadarajan, I think this was on Friday afternoon.

He was being crossed on differences between his model run and the Company's model run, and he said, well, the main difference is that his run was later in time and so it included different fuel inputs and that that was normal, that input assumptions change over time, so they changed the absolute outputs. And I think he used the phrase this is why we focus on the comparison between the scenarios rather than the absolutes. And I agree with that. I think that is important. Input assumptions are simply estimates and they will change over time, but the real value is in the comparison.

And I get very concerned -- again, I've been listening, and I heard witness -- CIGFUR witness Muller testify that he would use such rate projections to make business decisions, to make decisions about where to locate a plant. And that's very concerning to me because I know that those absolute values can change based on changes in the input assumptions, based on change in inflation, interest rates, fuel costs.

And so if he’s going to do that, one, I get concerned what would he be comparing it to. Would he be comparing our projections to another utility’s current rates if they don’t have a projection, which would lead to a bad business decision or could lead to a bad business decision, or if that other utility does provide a projection, there’s no way to guarantee that we’re using the same input assumptions. And so he could be looking at apples and oranges projections and, again, make a bad business decision.

And so not only do I think it's unrealistic and not of value to provide those projections; I think it could be dangerous and misleading for some customers that may not understand that those projections can’t be relied on and can’t be taken as a certainty of what the rate will be in 10 or 15 years, but instead they’re estimates and they’re good for comparison purposes, but shouldn’t be taken as absolutes.

Q Thank you. That was a very long answer to a yes or no question. So -- but I wanted --

A Well, I wanted to make sure that it was clear.

Q And I’m going to revisit some of the things you said --

A Okay.

Q -- so I think it's helpful. But one thing I do want to make clear, at the beginning, just to make sure, you did say that the grid investment costs that you've modeled two to three years out are not included in the PVRR calculations, correct?

A Yes, to the extent that they are not related to generation additions.

Q All right. And then you -- in your answer you also mentioned that in discovery you asked for Intervenors to provide instances in which other utilities had provided long-term all-in cost forecasts, correct?

A Yes. I asked several Intervenors.

Q And do you recall that CUCA did respond to that data request and provided an email exchange between you and Kevin O'Donnell?

A Yes. Let me get to that.

Q Okay. So you're familiar with that email exchange?

A Yes.

Q Okay. And the exchange occurred on July 10th of 2021, correct? At least the final exchange, I should say.

A So I have some email exchanges from April and then -- I have some from April. I don't have the July one.

Q I see. I think the copy we produced signals that it was forwarded at a later date, but I think the last exchange between you and Mr. O'Donnell was on April 12th of 2021. Is that what you have?

A I have an exchange from April 15th.

Q Okay. Well, why don't I --

MR. SCHAUER: If I could have a second, I'd like to hand out an exhibit which is what CUCA produced in response to the data request Duke issued.

MS. NICHOLS: If I could, just for the record, note that the email exchange appears to have occurred in April of 2021, but the top of the email shows that it was forwarded somewhere on July 10th. So if that helps anyone clarifying what we're looking at.

MR. SCHAUER: Yeah. And thank you. That's something that I realized as I was starting to embark on this line of questions, so thanks for clarifying that.

Chair Mitchell, I'd like to mark this as Tech Customers Operations Panel Rebuttal Cross Examination Exhibit 1. All right. And so --

CHAIR MITCHELL: Okay. One minute, please, sir.

MR. SCHAUER: Sorry.

CHAIR MITCHELL: We're actually going to identify this document as Tech Customers Bateman Rebuttal Cross Examination Exhibit 1.

MR. SCHAUER: All right. Thank you. Thank you, Chair Mitchell.

(Tech Customers Bateman Rebuttal Cross Examination Exhibit 1 was marked for identification.)

Q So the exchange shows April 12th, 2021, at least on the copy that I handed you. And it is an email from you to Mr. O'Donnell and Mr. Maness of the Public Staff, and there's an Excel sheet attached to --

A Yes.

Q -- the email exchange?

A Yes.

Q Are you familiar with that Excel sheet?

A I am.

Q Okay. I have attempted to print out the Excel sheet which was attached. And as all Duke's modeling Excel sheets go, they are unwieldy, but I think I captured everything to the best of my ability.

If you flip to the first page of the Excel

sheet which says Summary Chart --
A Yes.
Q -- at the top it shows that this calculation includes the IRP Base Plan. Could you explain what that is?
A That's from the 2020 IRP. It was the base case plan.
Q Okay. And then the next column is All T&D, Including Grid Mod. Can you explain what that means?
A Yes. And I want to give a little bit of background here.
Q Sure.
A And so Mr. O'Donnell had taken a number that Lynn Good had referenced in, I don't know, some public forum, maybe an investor call or something like that, about how many billions of dollars we would spend on capital investments for T&D over the next five years. So Mr. O'Donnell took that and then misunderstood that amount, and then he assumed it was all DEC when, in fact, it was both DEP and DEC. And then he assumed it was grid improvement on top of our base T&D spend, but it was not. It was total T&D spend.
And so based on those two assumptions, he calculated some bill impacts using, you know, standard

revenue requirement calculations and then started sharing those with legislators. And so I felt the need to correct his incorrect assumptions because they were leading to very distorted results that were being shared publicly.

And so we took that, you know, and I forget, it's probably in the details here, "x" billion dollars, spread it, made some high-level assumptions to spread it to both DEC and DEP. And then, you know, instead of being on top of base spend, it was the total amount, so we modeled that correctly and then just made a high-level assumption for after the five-year period that, you know, some normal level of spend would continue. So pretty high-level assumptions, but more accurate than what Mr. O'Donnell had modeled. And so we kind of revamped that and then shared with those assumptions what the bill impacts would be for that T&D.

And so I want to give that background that, you know, these were never intended to be you can absolutely count on this is going to be your bill impact in 2030 or 2035. These were not based on detailed plans, and it was to correct, you know, grossly wrong estimates that were being shared publicly to get more in the right ballpark of what people should expect.

Q And the calculation you performed was through 2035, so it was a 15-year forecast?

A Yes. And then I also want to note, you know, it’s on here, Note 2 says it “Does not include coal ash, maintenance investments at existing non-fossil plants, general or intangible plant, depreciation of existing rate base or changes in ADIT for existing plant in service, or other changes in rate base, changes in O&M, changes in tax rates, or other unforeseen cost changes. High-level analysis, assumes perfect ratemaking for all costs, costs allocated at a high level, not at a more precise cost of service level as would be done in rate case.”

So I think that’s pretty clear that these -- even these are not all-in costs and should not be relied on to, you know, make business decisions or like for customers to make business decisions, that these are high level and they are not all in.

Q Given the risk of customers performing bill impact analyses with incorrect assumptions that would produce distorted results, wouldn’t it be better for ratepayers and the public for Duke to perform those calculations and provide accurate information for them?

A No, because during this process, you know, Kevin -- Mr. O'Donnell and I had some back and forth, and one thing that he said is that we both know that both of our projections are wrong because they are simply projections based on inputs, and those inputs are just projections and they might -- they may or may not change over time.

Q Right. Just like the PVRR calculation is inevitably going to be wrong because it's going to evolve.

A And I -- I have said that I thought the PVRR was valuable for purposes of comparing portfolios, and that's what I think the value of that is.

Q So one of the reasons you said that Duke could not perform an all-in long-term price forecast was because of interest rates, inflation, fuel costs, and a few other assumptions, correct?

A Yes.

Q All right. And the PVRR calculation which Duke provided as part of the carbon plan includes assumptions about interest rates, inflation, and fuel costs, does it not?

A Yes. And so I didn't say that you couldn't do projections, you couldn't do modeling that includes those assumptions, but where I get concerned is if -- and I think witness O'Donnell stated this, that we should be held accountable to that, that it should be taken as certainty, that those will be the bill impacts in 10 or 15 years. And I think in the portfolios that we've presented in this docket, you know, no one has made that assertion that these are the absolute, you know, costs that you can count on 15 years from now, but using consistent assumptions across the portfolios, that you can have -- that they are valuable for comparing portfolios.

MR. SCHAUER: No further questions.

CROSS EXAMINATION BY MS. GRUNDMANN:

Q Good morning.

A Good morning.

Q Ms. Bateman, Carrie Grundmann on behalf of Walmart. I actually do want to follow up on one of the issues that you discussed in one of your responses to Mr. Schauer's questions. You indicated that in the course of discovery you asked the Public Staff, CIGFUR, and CUCA if they were aware of forecasts -- 10- to 15-year forecasts being provided by any other parties, and you indicated that no one had such forecasts.

A Correct. Or no one provided any forecast.

MS. GRUNDMANN: Your Honor, I'd like to mark an exhibit for the record.

A And we did not ask Walmart because Walmart didn't --

Q Ask the question.

A -- file testimony on this issue.

Q But had Walmart been asked, I might have been able to have provided a response.

MS. GRUNDMANN: Your Honor, I'd ask that we mark this exhibit as Walmart Bateman Rebuttal Cross Examination Exhibit 1.

CHAIR MITCHELL: All right. The document will be marked as Walmart Bateman Rebuttal Cross Examination Exhibit 1.

(Whereupon, Walmart Bateman Rebuttal Cross Examination Exhibit 1 was marked for identification.)

Q Ms. Bateman, do you have a copy of this exhibit in front of you?

A I do.

Q I will represent to you that this is an excerpt. It is the front page and then page 8 from the Virginia State Corporation Commission's Final Order in Case Number PUR-2020-00134 which involved Virginia Electric and Power Company doing business as Dominion

Energy.

A Okay.

Q And it involved requirements under the Virginia Clean Economy Act. Do you have some base level familiarity with that legislation?

A Yes.

Q And to the extent we need to refer to it, I have my copy here, but do you have the CIGFUR II and III Carolina Utility Operation's Panel Direct Cross Examination Exhibit 7 in front of you? It is a copy of the VCEA. It's entirely possible you don't have it, and if so, I --

A Was it -- yeah. I was going to say if it was handed to me on my direct testimony, I have it somewhere in here, but --

Q I have it. So to the extent you end up needing to refer to it --

A Okay.

Q -- I'm happy to do that.

A Okay.

Q But if I could direct your attention to the second page of this exhibit which is marked as page 8 of the Commission's Order. Are you aware that beginning in 2020 and continuing for 15 years that the utilities in

Virginia are obligated to file annual RPS plans with the Virginia State Corporation Commission?

A Generally familiar.

Q Okay. And as part of those plans, directing your attention here to page 8, do you see that the Virginia Commission has directed Dominion to file projected customer bill impacts information through 2035 associated with its RPS development plan, and that among other things, it has to provide customer bill impact information over the next 10 years for its least-cost plan, the Company’s preferred plan, and any additional plans presented by the Company?

A I see that here, but I also want to note that I actually spoke with Bob -- Robert Drexler from Dominion about the projections that they provide, and he indicated that even their projections are not all-in projections, that there are certain costs that are excluded.

Q I guess my point was is you were asked if any parties had that, and this does indicate that there is another utility, one who is in a neighboring jurisdiction that is providing bill impacts associated with complying with clean energy legislation.

A There is not -- they are not providing all-in bill impacts, and that’s what -- what’s what my testimony was. I mean, we provided bill impact -- bill impacts of the carbon plan in the carbon plan in Appendix E, but we -- they were not all-in bill impacts. And just like Dominion provides bill impacts for certain things in their legislation, they are not all-in bill impacts.

So I think that's what I was saying, is that we don't have -- I couldn't find another utility that provided all-in bill impacts that would encompass everything such that a customer could look at that and make decisions about what their future rates would be.

Q But you do understand here that separate from a PVRR, the Virginia Commission has ordered the utility Dominion to file bill impacts associated with the compliance with the VCEA?

A Yes. And --

Q And you understand that that's --

A And we filed bill impacts associated with the carbon plan in this proceeding.

Q Bear with me just a second. As part of the VCEA, you understand that the Company is obligated, that Dominion is obligated to retire its carbon-emitting generation. Are you aware of that?

A I'm not familiar with all of the details of the requirements.

Q Well, can you accept that subject to check?
A I can accept that subject to check.
Q And are you aware that one of the other steps that has occurred in Virginia to address the Virginia Clean Economy Act's unique legislation is that specific cost allocation methodologies were proposed and adopted by the Virginia Commission?
A I have no reason to dispute that.
Q And that as part of those methodologies, all costs and benefits will flow through those riders, including fuel costs for Virginia -- for carbon-free resources that comply with the VCEA?
A So I just want to be clear. So there are certain costs that flow through their riders. Is that what you're saying? They're not all -- not all costs that flow to customers are in the riders, though.
Q I'm just asking if you understand that there's a specific methodology that recovers all cost associated with those particular facilities?
A So I'm not familiar with that, but I can accept that subject to check, that there are specific costs that flow through riders.
Q Thank you.
MS. GRUNDMANN: Those are all the questions

that I have.

CHAIR MITCHELL: All right. Public Staff?

MS. EDMONDSON: No questions.

CHAIR MITCHELL: Okay. Redirect?

MS. NICHOLS: Sure.

REDIRECT EXAMINATION BY MS. NICHOLS:

Q Ms. Bateman, if you would look at the exhibit that Ms. Cress provided to you on cross examination regarding the recent Public Service Commission South Carolina Order.

A Yes.

Q She asked you to read a paragraph on page 7 of that Order at the bottom of the page.

A Yes.

Q And I just wanted to note, if you could look at the cost differential, the PVRR differences between Portfolio C1 and that Duke had -- was Duke's preferred portfolio and what the Commission adopted, what's the magnitude of the difference between those two amounts?

A It's 3.4 billion, but given the magnitude of the numbers, it's pretty small.

Q And --

A Relatively small.

Q And could the IRA impact what those amounts end up being?

A Absolutely.

Q And if you would turn to page 9, could you read paragraph 4 of the Findings of Fact there?

A “The Utilities and stakeholders are given clear and consistent direction of the regulators regarding resource planning. The Utilities being expected to implement the best practices in an ever evolving situation are not bound by a specific resource plan since by the very nature, those plans may change as more information becomes available.”

Q And then could you look at paragraph 6 and read that?

A “The Commission decision to adopt A2 does not interfere with efficiencies of dual-state planning. It is incumbent upon the Utilities to recognize that North Carolina and South Carolina have different statutory structures which at times align. In other instances, however, due to specific regulatory requirements unique to a single state, dual-state planning must accommodate those differences.”

Q And is Duke working to come up with a framework to address dual-state planning and potential state differences?

A   Absolutely. And that's what I referenced when I testified in my direct testimony, and then I state -- well, when I was on the stand for direct testimony, and then referenced in my rebuttal written testimony that we are working on developing that framework that can maintain the dual-state system which we believe is a benefit to customers and has been a benefit to customers over many, many decades, but allow for differences in state policy.

Q   And CIGFUR has taken the position in this proceeding that if costs are not -- that costs should be allocated to South Carolina, and if those costs are not authorized by the South Carolina Commission, that shareholders should have to bear those costs. Do you agree with that position?

A   No. I mean, I think there's a basic fundamental principle of utility ratemaking that a utility should be allowed an opportunity to recover its reasonable and prudently-incurred costs in the provision of service, utility service. And so I think as we're looking forward, that, you know, we are developing this framework, but I don't think that this Commission can impose cost on South Carolina. I don't think North Carolina can impose cost on South Carolina. I think we need to develop this framework that if North Carolina wants to build a certain generation project and South Carolina doesn’t, that there’s an opportunity to allow that, where North Carolina customers have North Carolina generation that they pay for and receive all the benefits of and South Carolina in the same way can have South Carolina generation that maybe they pay a hundred percent of and receive a hundred percent of the benefits of, and then generation that is jointly -- that serves both states.

But I don’t think that -- especially as we look forward to what we should invest in going forward, that it would be fair to order the Utility to pursue certain generation. And then knowing that South Carolina doesn’t want to pay for it, but ordering that some of the costs get allocated to South Carolina, so there’s no opportunity for the Company to recover its reasonable and prudently incurred costs.

So I think that’s a fundamental principle that we need to keep in mind as we navigate through this.

Q   Thank you.

MS. NICHOLS: Nothing further.

CHAIR MITCHELL: All right. Let me see if there are questions from Commissioners. Okay.

Commissioner Duffley?

EXAMINATION BY COMMISSIONER DUFFLEY:

Q Good morning, Ms. Bateman.

A Good morning.

Q So I'm a lawyer, not an accountant --

A Okay.

Q -- so I have some accounting questions that I just want to get clear in my head.

A Yeah.

Q So in the filings, the Company has stated that they modified their petition and they're not seeking deferral of cost related to long lead-time resources; is that correct?

A Correct.

Q So I just want to know what accounts are going to be used.

A Yes.

Q So will those costs go first into Account 183 or 183.2, or both?

A So I'm not familiar with 183.2.

Q Okay. So 183 is Preliminary Survey and Investigation Charges and 183.2 is entitled Other Preliminary Survey and Investigation Charges.

A So I would need -- I would need to check on

that. We typically just refer to 183 as 183.
Q Okay. That's fine.
A I apologize.
Q And then once the activities -- either you have filed a CPCN or you have obtained a CPCN, those charges will move to Account 107, or those costs will?
A So I'm not sure what the trigger point is, but if that project is pursued, so that could be the trigger point of the CPCN, then they move to 107.
Q So you answered my follow-up question, was where is that trigger point, and you're not sure today?
A Correct.
Q Okay. And then ultimately if the project reaches commercial operation, those costs would move to Account 101?
A Correct.
Q Okay. Thank you. And if the charges do not -- or if the project does not meet commercial operation at that -- when you know that point is when you might seek a deferral?
A Yes. So if it's determined that it's no longer prudent to pursue that project, then the cost would most likely -- if we thought they were probable of recovery, we would likely move them to a 186 deferred debit account

and then seek permission to move them to a regulatory asset from this Commission.

Q Okay. Thank you for that. And then you heard Ms. Boswell's testimony regarding Section 62-110.7?

A Yes.

Q I didn't see any response in the rebuttal -- I'm in the legal brief right now -- and I just want to confirm, when I read this, I wasn't quite sure, have you -- do you consider this a 110.7 proceeding or do you see -- I understand you say there shouldn't be a separate proceeding, but are you saying this equates with that proceeding?

A So I'm not saying either of those. I believe we address kind of the legal side of that in our September 9th comments. From my perspective it's really -- it goes back to that basic ratemaking principle. If it's reasonable and prudent for the Utility to pursue these development activities and we execute them in a reasonable and prudent manner, then we should be allowed an opportunity to recover those costs.

Q I understand that answer. Thank you. Moving to page 6 of your rebuttal testimony.

A Yes.

Q So you're responding to Public Staff's testimony regarding cost allocation of carbon plan costs between DEC and DEP. And you obviously heard Mr. McLawhorn's testimony in which he had concerns about what happens if the merger is unsuccessful, and then we're several years down the road and no work has begun with respect to closing this rate disparity. And I just want to give you an opportunity to talk about that, please.

A Yeah. And I appreciate that because I did hear that testimony, and maybe I was not clear in my testimony. My testimony is that I don't think we need to implement an interim solution, but I do agree with him that we need to be pursuing the merger, but concurrently developing alternative solutions if the merger is not able to be achieved.

Q Okay. Thank you for that clarification regarding that. And just remind me, how long did it take to align OPT-I and OPT-V rates? I've gone back to an old rate case --

A So I am --

Q If you remember.

A I am familiar because I believe that was actually right around the time of the merger, that DEC previously had OPT-I and OPT-G rates and now there's --

Q Is it G, G or V? Was it G?

A I think now the new rates are OPT-V.
Q V. Okay.
A So I think it used to be separated by industrial and commercial --
Q Okay.
A -- kind of SIC code, S-I-C code, but when they moved to OPT-V, it’s now differentiated by voltage level and size.
Q But there was the use of gradualism with respect to those issues? Do you remember?
A I am not familiar with that.
Q Okay. Not a problem. And then my last question regards -- it’s on page 7. And it’s with respect to why in the P2 version is the differential larger than all the other portfolios?
A And so I think it just has to do with the timing of when resources go into effect. So I had looked at that, and I think it is just an issue of timing.
Speaking of those large files, I print on big paper. Yeah. I think it’s just timing of resources. There’s some production cost savings, but not a whole lot coming into service in 2026 in those portfo--- or differentiation between what’s coming into service in 2026.

Q Okay. Thank you.

CHAIR MITCHELL: All right. Commissioner Clodfelter?

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Ms. Bateman, good morning. I'm not sure how far I want go go with this and I'm not sure how far you can go with this, but I just -- I want to try because it's just gnawing at me. And I recognize that this is something we'll probably be talking about or someone will be talking about a lot more in 2024 and 2026 and 2028 than we can talk about today. But in your rebuttal testimony you do have a little bit of discussion about the state alignment problem, and I understand from your direct testimony you say that the Company is trying to develop some framework to address the contingency that the South Carolina Public Service Commission and the North Carolina Utilities Commission diverge.

A Uh-huh.

Q And I understand that, and I know you're working on it and you don't have a lot of detail you can share with me today, but one of the things you say on page 11 of your rebuttal testimony is that you do agree with CIGFUR on the principle that if there are costs that one jurisdiction bears, but the other jurisdiction refuses to share in, that the benefits should go to the jurisdiction that's covering the cost.

A Yes.

Q And what's gnawing at me is I'm just sitting here trying to figure out how that could possibly happen. I mean, let's suppose -- and I think with a concrete example, because that's the way I think about it.

So suppose we here say we love Bad Creek and we love offshore wind and we want you to go all out on Bad Creek and offshore wind, and the Public Service Commission says -- in South Carolina says we're not going to have South Carolina ratepayers paying for those, how do we get all the benefits?

I mean, the energy -- the energy that's going to land from the undersea cable from that offshore wind facility is going to go onto the grid, and it's going to be available across the entire by-state grid. It's going to be -- the capacity is going to be available when it's needed for peaking. The energy is going to be available to customers everywhere. And if you've got a reliability concern, you're going to call on the resource for South Carolina customers as well as North Carolina customers.

A Yeah.

Q How do we get a hundred percent of the benefits?

A Yeah. And so we have been thinking through this, and so I can lay out, you know, some things that -- some kind of current thoughts, and they all have issues that need to be worked through and fleshed out. But one idea, which is probably more complex -- and the short answer is it’s in the accounting.

So one idea is to look at marginal cost. And so you would have a North Carolina stack and a South Carolina stack. And I kind of wish my co-panelist Nelson Peeler was here with me because he could explain this better than me. But when you have the dispatch of the system, you would dispatch both, and let’s say you used offshore wind. If that was a North Carolina only resource, that would be in the bottom of the North Carolina stack. And then you would kind of dispatch up.

And so if South Carolina didn’t have any South Carolina specific resources, they would reach the top of -- or North Carolina would reach the top of the stack more quickly and there would be a transfer price for that generation that is at the top of the stack.

And so you would have like the variable -- so whatever unit is being dispatched at the top of the stack, the most expensive variable cost unit, you would take -- South Carolina would have to purchase that energy from the North Carolina stack, and so it would be transferred over in an accounting adjustment to move that cost to South Carolina.

And then there would be -- I believe Public Staff asked about this -- there would be a capacity component as well. And so some sort of marginal capacity cost. Now, how you determine that, you know, there’s many different ways that you could do that, but some sort of capacity cost would have to transfer over. So that’s one way to look at it, is marginal, you know, marginal energy, marginal capacity.

Another way to look at it is average embedded. And so using the wind example again, you would look at the total KWh output from that wind generation and the total KW at the times of peak from that wind facility, and you would adjust the North Carolina allocation -- you would adjust your allocation factors to remove the KW and the KWh that were served from that wind generation facility, would remove that load from the factors and then use an adjusted factor with that load removed to allocate the rest of the generation portfolio, both the energy cost, the variable cost, and the capacity or demand costs.

And so those are just an example of two different ways that you could do it. There are probably others. We are early on in looking at this. But there has to be a way -- we believe there is a way to do it, and we're hopeful that there is a way to do it that is acceptable to both North Carolina and South Carolina that's fair.

And so what's not fair is for North Carolina to pay a hundred percent for a generation facility and South Carolina to get energy from that facility for free. But we think there is a way to do it either by looking at marginal cost and developing a stack for each state, kind of similar to how we do the JDA today, or looking at it from an embedded cost or an average cost perspective.

Q Thank you for that. I think that's as far as we ought to go or I want to go today because this is a -- I mean, it's a long-term contingency, but I just wanted to get started thinking about it.

A Yeah.

Q And you've given me something to chew on. Thank you.

A Okay.

EXAMINATION BY COMMISSIONER McKISSICK:

Q And my thoughts were along similar lines as

Commissioner Clodfelter. What have you thought about in terms of the Red Zone improvement costs, particularly in light of where some of the improvements and upgrades would occur? I mean, and you may not be in a position to elaborate further today, but I think it's a concern that we all share.

A Are you talking about North Carolina/South Carolina or --

Q Yes.

A Okay. So for transmission, I believe transmission is a little different than generation. For transmission there are system network customers, and they should pay for all of the system network costs. And so I think that's -- if you're a transmission customer of the system, you need to pay for all of the costs. And I think the Red Zone projects would fall into that.

Now, I have read testimony both by Public Staff witness McLawhorn and in I believe the NCEMC comments where they talked about that those projects -- well, I'll talk about NCEM--- well, Public Staff, I think witness McLawhorn said that they are projects that are resulting from state policy, and I believe NCEMC referenced an example in New York where some transmission projects were designated as state policy projects. I think if you designate them as state policy projects, then you make the argument that they should be North Carolina only, but if they are simply network upgrades to accommodate new generation on the system, they would be network costs that would be paid by all network customers.

Q All right. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q All right. Thank you, Ms. Bateman, for your testimony today. I don't have much for you, just to kind of pile on to questions that you've already been asked.

Did you hear Mr. McLawhorn's testimony that he provided in the hearing room several days ago?

A Yes, I did.

Q Okay. I took away from his testimony a sense of -- a strong sense of urgency to address the discrepancy between DEC and DEP rates, and you've addressed that some in your prefiled testimony and some in response to questions you've been asked today, but this is my -- this is my concern.

You know, there is a -- there is some dissonance between where the Public Staff is and where the Companies are on the issue of addressing the disparity in the interim before we have a final decision on merger of the two companies. And so can you respond to -- can you respond beyond what you've already said in your testimony, having heard Mr. McLawhorn's strong feelings that he expressed in this room the other day?

A Yeah. Yeah, I can. And I'll say that I don't know that Mr. McLawhorn and I are -- that our views are that far apart. So one thing that I want to clear up is -- and I don't think Mr. McLawhorn is saying this, but that there should -- that any existing rate disparity between DEP and DEC is not the result of something that Duke has done wrong or that Duke should have been working since the time of the merger to make these rates more even or close that gap.

We seek to make the rates for DEP and DEC as low as possible. We do not try to make them more even. And that would be contrary to our requirements to avoid cross subsidization per the Regulatory Conditions Code of Conduct, et cetera. We try to avoid cross subsidization, so we do not just charge DEC customers in order to make the rates more even.

But I don't read witness McLawhorn's testimony to imply that we've done something wrong or that we should have been addressing the existing rate disparity. In fact, when he lists the reasons for it, he references several things that DEP was required to do, such as the purchase of solar PPAs under PURPA, you know, previous purchases under PURPA. So I just -- I want to be clear on that issue. I don’t think we’re as far apart as it might appear.

When I read witness McLawhorn’s testimony in both this docket and the 2022 solar procurement docket, my understanding is that his view is that because HB 951 is a statewide policy, a statewide mandate for carbon reduction, that the cost should be spread more evenly between DEP and DEC and that either both utilities should be able to -- should be required to individually meet that mandate, or if they’re going to jointly meet the mandate the way that we’ve modeled it and through that joint -- through meeting the mandate through a joint plan, more of the costs are -- end up in the DEP service territory, that there has to be a way to more evenly spread those costs because otherwise, you would have DEP customers subsidizing DEC, that they would be paying for costs to -- for DEC to comply with the requirements of HB 951.

And so I think that is a valid point and I do think it’s something that we need to work on. But when I look at the differences in 2026 in the revenue requirements, four of the six portfolios actually reduce the rate disparity in 2026, and then the other two, P3, DEP’s rates increase by 8 cents more per megawatt hour. And just to translate that, that’s approximately 8 cents on the typical residential bill. Portfolio 4 is 55 cents difference between the DEP and DEC rate impacts, and that’s about 55 cents on the typical residential bill.

When I contrast that with the differences in 2030, the 2030 difference is the DEP residential bills are anywhere from $12 to $27 higher than the DEC typical residential bills. So I think 2030 is -- you know, we need to address this issue before then. I don’t see the issue before 2027.

I will say, you know, given all that, so it’s my testimony that it’s not necessary to implement a remedy before 2027, and I don’t even know that it’s really -- I don’t think it’s necessary and I think any solution has complications to it, and we testified that the most straightforward solution was a merge of the utilities, and that’s a pretty complicated process.

So -- but given all of that, if this Commission does think that there needs to be a remedy before 2027, I can say that in our upcoming rate cases we will have an alternative option for the Commission on how to split the cost of certain projects between DEP and DEC.

Q Okay.

A It's not our base recommendation, but we will have an alternative option.

Q Okay. Thank you for that explanation. And just following up with you on one issue, so the Companies have stated an intention to pursue merger and have provided us with a timeline, an anticipated timeline. And we don't know what the outcome of a merger request would be, given that you have to -- the Companies would have to achieve approval at multiple levels.

I want to make sure I understood your testimony to Commissioner Duffley. The Companies would be working concurrently on a fallback plan were the merger not to be approved --

A Yes.

Q -- as to allocation of cost between the two Companies; is that correct?

A Yes.

Q Okay.

A And we would work together with the Public Staff on that --

Q Okay. Okay.

A -- on both.

Q Thank you for confirming. I just want to make sure I was clear there.

Okay. I have one last question for you. I'm hoping you can answer. If not, then I'll ask somebody down the line. Does -- do the Companies have to pursue or secure approval on the Bad Creek project from South Carolina?

A I would ask that question of the Long Lead-Time Panel.

Q Okay. Got it. Okay. All right. That's all I have.

CHAIR MITCHELL: Let me just make sure no other questions have come up. Okay. We'll take -- we will take our morning break, and we will be back on the record at 11:00.

(Recess taken from 10:41 a.m. to 11:00 a.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. We will continue with questions on Commissioner's questions. Who's up first?

MS. CRESS: You want to go ahead, if we're going in alpha order?

MS. GRUNDMANN: No.

MS. CRESS: Okay. Thank you, Chair Mitchell.

EXAMINATION BY MS. CRESS:

Q Ms. Bateman, I have a few follow-up questions

your your discussion with Commissioner Clodfelter, and I just want to make sure I understand. So if North Carolina ratepayers are receiving all of the output, all of the benefits from a generating asset, then North Carolina ratepayers would also be allocated all of the cost for that asset. Is that consistent with your testimony?
A Yes.
Q Is that the same thing as the direct assignment method that you discussed in your prefiled rebuttal testimony, or is that something different?
A That would be -- yes. That’s the same.
Q So that --
A Yes.
Q -- that’s what you were discussing --
A Yes.
Q -- with Commissioner Clodfelter --
A Yes.
Q -- was that --
A That you would have North Carolina only -- you would have joint resources, and then going forward you could have North Carolina only resources or South Carolina only resources and joint resources.
Q Thank you for that. Now, the direct assignment

method that you were discussing with Commissioner Clodfelter and as referenced in your rebuttal testimony would be a departure from the cost allocation assumptions in the carbon plan; is that right?

A Correct.

Q So given that it would be a different cost allocation methodology or solution, I think is the word that you used when discussing the state alignment issue, given that it would be different than the assumptions made on that issue in the carbon plan, wouldn't it be reasonable to ask Duke to supplement its filings with the information as modeled under these different assumptions?

A So I don't think we're at a point yet to model this. We're still in the development -- still very much brainstorming and developing these frameworks, so it's not at a point where we could model a portfolio with assumptions under this new framework. It's not developed to that level yet.

Q Okay.

MS. CRESS: If you'll just give me one moment to check my notes. Chair Mitchell, I'd just ask that the Commission take Judicial Notice of the North Carolina Retail Production Demand and Transmission Allocation Factors for DEP and DEC, as set forth in Exhibit A and B to the Agreement and Stipulation of Partial Settlement filed on September 13th, 2022, in Docket Numbers E-2, Sub 1300, and E-7, Sub 1276.

MS. NICHOLS: No objection.

CHAIR MITCHELL: All right. The Commission will take Judicial Notice.

MS. CRESS: Thank you. Nothing further.

CHAIR MITCHELL: Okay.

EXAMINATION BY MS. GRUNDMANN:

Q Good morning again, Ms. Bateman. I wanted to follow up on some of the questions that you were asked by Commissioner Duffley. I think that she started by having you confirm that the Companies have withdrawn their request for deferral accounting treatment of the long lead-time resources. Do you remember that question?

A Yes.

Q And then she asked you -- and I am not an accountant and I want to only kind of set the ground for my questions, but she had talked with you about if you sought -- subsequently sought a CPCN for long lead-time resources, and she asked you whether the cost -- did she ask you if the cost would move from FERC Account 183 to 107? Is that --

A Yes.

Q And I think your response said if you sought a CPCN, that that's what would occur.

A So no. I said that that could be the trigger point, but I wasn't sure what the trigger point was for moving cost from the 183 account to the 107 account. I did get a little bit more information during the break, and it's still -- it's a little bit nebulous, but it's when a decision is made to move forward with the construction project. That's when it moves to 107. So that could be some, you know, senior management approval, that could be the application for a CPCN, it could be a variety of triggers, but when a decision is made to move forward with the construction project, that's when the costs move to 107.

Q Okay. So my notes -- I appreciate that subsequent clarification because I do think it helps, but my question -- my notes don't reflect it in the way you just described it. The way I wrote it is that you said if you sought a CPCN that would happen, and so my question was are there long lead-time projects for which you -- that it's your understanding that a CPCN would not be needed?

A I would ask the Long Lead-Time Panel.

Q Thank you, Ms. Bateman. That's all my

questions.

A Yeah. I did want to clear up that it's not necessarily that a filing for a CPCN is the trigger to move it to 107.

Q No. Thank you. I appreciate the clarification, and I'll check on this issue with the Long Lead-Time Panel. Appreciate you.

MS. GRUNDMANN: That's all the questions I have.

EXAMINATION BY MS. EDMONDSON:

Q Good morning, Ms. Bateman.

A Good morning.

Q Just a couple questions. In response to Commissioner Clodfelter's questions about separating the physical loads in energy between jurisdictions --

A Yes.

Q -- would you agree that rates and revenues today are set on an embedded or average cost basis, and only the small curtailable loads are set on a marginal basis?

A I'm sorry. Say that again.

Q So that rates and revenues are set on an embedded or average cost basis, and marginal basis is generally just used for small curtailable loads?

A So I might disagree to some extent. So I would agree that rates are generally set on average embedded cost. Especially for joint resources that are shared and allocated, the allocations are of embedded average cost. I do think I would point to the JDA where there's transfers between DEP and DEC. I believe those are at more of a marginal cost. Certainly, purchases and sales with other utilities that are either economy purchases or -- I'm blanking out on this -- like bulk power marketing sales would be done at more of a marginal cost basis. So there are some things that are marginal, but mostly embedded.

Q Okay. Thank you. Is it possible to separate the physical capacity demands and the energy consumption of two interconnected jurisdictions without severing the transmission and distribution wires that interconnect the two jurisdictions?

A So I don't have an answer to that, but I think, you know, what we're proposing, the framework that we're proposing doesn't involve a physical separation, but would be achieved through the accounting. And it would still maintain the duel-state system, and all of your existing generation would still be allocated or jointly shared between the states. But as we move forward, could we, through accounting mechanisms, have generation that is directly assigned to one state versus the other.

Q Could you give more -- any details about how the accounting would work or how the cost would be allocated based on this accounting method?

A So not beyond what I provided in response to Commissioner Clodfelter.

Q Okay. Thank you.

MS. EDMONDSON: That's all I have.

CHAIR MITCHELL: Duke?

EXAMINATION BY MS. NICHOLS:

Q Just Ms. Bateman, you cleared up the question about when project costs move from Account 183 to 107. Did you also get some clarification on Account 183.2? Is that something we use?

A No, that we have -- we would put cost in just 183.

MS. NICHOLS: Nothing further.

CHAIR MITCHELL: All right. At this point, Ms. Bateman, you may step down, and you are excused. Thank you very much for your testimony this morning.

THE WITNESS: Thank you.

(Witness excused.)

CHAIR MITCHELL: And I'll take motions.

MS. NICHOLS: We don't have -- Ms. Bateman doesn't have any exhibits, but we do have her summary of her rebuttal testimony that we would move into evidence.

CHAIR MITCHELL: We'll copy her summary, testimony summary, into the record at the appropriate time.

MS. NICHOLS: Thank you. Nothing further.

(Whereupon, the summary of rebuttal testimony of Laura Bateman was copied into the record as if given orally from the stand.)

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Rebuttal Testimony – Carolinas Utilities Operations
Laura Bateman
Carolinas Carbon Plan
Docket No. E-100, Sub 179

I am Laura Bateman, Vice President of Carolinas Rates and Regulatory Strategy. I will provide a summary of my rebuttal testimony to respond to various intervenors regarding several rate – related issues.

First, my rebuttal testimony reiterates the Companies' commitment to pursuing a merger of DEP and DEC and the Companies' view that a merger will be the most straightforward solution to resolving rate differences over the long term. The Companies understand the Commission's direction to "get to work on a solution to this significant issue" and believe that the merger, which the Companies intend to diligently pursue, is that solution. However, the Companies disagree with the Public Staff recommendation that an interim solution for rate differences is needed at this time in advance of pursuit of a merger. The current rate differences related to legacy system conditions that have occurred over time largely due to factors outside of the control of the Companies or the Commission. The Companies agree that over the longer-term, Carbon Plan investments will likely contribute to widening rate differences. However, as is shown in my testimony, those Carbon Plan related investments are not projected to result in any material widening until after 2026. With a merger completion targeted for January 1, 2027, the Companies do not believe that it is necessary to develop an interim solution to rate differences, when such a solution would not be needed if a merger can be completed. However, in the upcoming PBR rate cases, the Companies will present an alternative allocation approach for the RZEP for the Commission's consideration. . The projected impact of the Carbon Plan investments on current rate differences prior to the targeted merger is minimal to non-existent. In only two of the six portfolios are the $/MWH revenue requirements through 2026 greater for DEP than for DEC using the existing direct assignment. Thus, the Carbon Plan investments are not materially, and in most cases not at all, widening the rate differential through 2026.

Second, I explain why "all-in" customer rate projections are neither feasible nor necessary in this proceeding. The Companies do not prepare a forecast that includes all costs and revenues that goes out for 10 or 15 years. Based on feedback from the Public Staff, the Companies included average annual customer rate impacts based on the Present Value of Revenue Requirements ("PVRR") for the first time in the 2020 Integrated Resource Plan ("IRP"). The PVRRs in the IRP have never included all future revenues requirements of the Company, but only those caused by the resource plan. This metric is used as a valuable tool to compare one portfolio to another in terms of cost to customers. The Company continued this approach in the Carbon Plan. These rate impacts were never intended to try to predict exactly what a customer's all-in rate will be, but instead were meant to be a valuable tool for comparing resource plans. As evidence of the fact that an all-in cost projection over a 10 year period is not reasonable, no intervenor has identified a forecast of similar scope and duration from other utilities.

Even if the Companies were to try to produce such a forecast, it would inevitably be wrong due to the number of different factors that impact rates – interest rates, inflation, fuel costs, storms, government regulations, amortization periods for deferred costs, etc., over many of which the Companies have no or limited control.

Finally, I address the concern raised regarding how costs should be allocated in the event the Public Service Commission of South Carolina ("PSCSC") makes different decisions from this Commission on Carbon Plan investments. The Companies believe that the focus of this proceeding should be on the near-term resource development and procurement activities and, as stated in the Carbon Plan, such near-term resources are no-regrets resources. All Carbon Plan and Supplemental Portfolios include adding at least 7,000 MWs of solar to the system to meet the 70% reduction target, given this and the fact that North Carolina accounts for approximately 80% of the combined DEC and DEP load, the anticipated solar and solar plus storage sought to be procured prior to the next Carbon Plan update will be needed for North Carolina customers regardless of decisions by the PSCSC. The Companies anticipate that by 2024 (the date for next biennial Carbon Plan update), there will be more clarity regarding the options available to facilitate continuation of the dual-state system while allowing for differences in state policy. The Companies' believe the solution to this concern is to use an allocation methodology, such as direct assignment, by which the full benefits of a resource are allocated to the jurisdiction that is assigned the cost of that resource.

This concludes my summary.

MS. CRESS: CIGFUR II and III would ask that Bateman Rebuttal Cross Examination Exhibit 1 be entered into the record.

CHAIR MITCHELL: All right. Hearing no objection, your motion is allowed.

MS. CRESS: Thank you.

(Whereupon, CIGFUR II and III Bateman Rebuttal Cross Examination Exhibit 1 was admitted into evidence.)

MR. SCHAUER: Chair Mitchell, Craig Schauer on behalf of CUCA. I'd like to correct an error in the record. When I introduced an exhibit, I misidentified it as Tech Customers Bateman Rebuttal Cross Exam Exhibit 1. It should be CUCA Bateman Rebuttal Cross Exam Exhibit 1.

CHAIR MITCHELL: All right, Mr. Schauer. For the record, the document that had been identified as Tech Customers Bateman Rebuttal Cross Examination Exhibit 1 will be corrected to be identified as CUCA Bateman Rebuttal Cross Examination Exhibit 1.

(CUCA Bateman Rebuttal Cross Examination Exhibit 1 was re-marked for identification (previously marked on page 73.)

MR. SCHAUER: All right. Chair Mitchell, we --

CUCA asks that CUCA Bateman Rebuttal Cross Examination Exhibit 1 be moved into evidence.

CHAIR MITCHELL: All right. Hearing no objection, your motion is allowed.

(Whereupon, CUCA Bateman Rebuttal Cross Examination Exhibit 1 was admitted into evidence.)

MS. GRUNDMANN: Thank you, Chair Mitchell. Walmart would ask that Walmart Bateman Rebuttal Cross Examination Exhibit 1 be admitted into the record.

CHAIR MITCHELL: Hearing no objection, that motion is allowed.

MS. GRUNDMANN: Thank you.

(Whereupon, Walmart Bateman Rebuttal Cross Examination Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right, Duke. Call your next witnesses.

MS. KELLS: Good morning. Andrea Kells for Duke Energy. Duke calls the Transmission and Solar Procurement Panel to the stand.

CHAIR MITCHELL: All right. Good morning, Mr. Roberts, Ms. Farver.

MR. ROBERTS: Good morning.

CHAIR MITCHELL: Let's get you sworn in.

DEWEY S. ROBERTS, II, AND MAURA FARVER;

Having been duly sworn,

Testified as follows:

DIRECT EXAMINATION BY MS. KELLS:

Q Good morning, Mr. Roberts. Are you the same Transmission Panel that appeared in this proceeding on September 19 through 21st of 2022?

A (Roberts) Yes.

Q Did the panel cause to be prefiled in this docket on September 9th, 2022 rebuttal testimony consisting of 43 pages and three exhibits?

A Yes.

Q And did the panel also cause to be prefiled in this docket on September 27threplacement rebuttal pages 27 and 43?

A Yes.

Q Do you have any changes to your rebuttal testimony or exhibits at this time?

A No. I do not.

Q And if I were to ask you the same questions today that appear in your prefiled rebuttal testimony, as updated on September 27th, would your answers remain the same?

A Yes. They would.

Q None of the panel's rebuttal testimony or exhibits are confidential, correct?

A That's correct.

Q Did you also prepare and cause to be prefiled a summary of the panel's rebuttal testimony?

A Yes.

MS. KELLS: Chair Mitchell, I move that the Transmission and Solar Procurement Panel's rebuttal testimony and summary be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. The motion is allowed.

(Whereupon, the revised rebuttal testimony and summary of Dewey S. Roberts II and Maura Farver were copied into the record as if given orally from the stand.)

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-100, SUB 179

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of:	)	**REBUTTAL TESTIMONY OF**
Duke Energy Progress, LLC, and	)	**DEWEY S. ROBERTS II AND**
Duke Energy Carolinas, LLC, 2022	)	**MAURA FARVER ON**
Biennial Integrated Resource Plan	)	**BEHALF OF DUKE ENERGY**
And Carbon Plan	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

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Q. MR ROBERTS, PLEASE STATE YOUR NAME, TITLE, AND BUSINESS ADDRESS.

A. My name is Dewey S. Roberts II ("Sammy"), and my business address is 3401 Hillsborough Street, Raleigh, North Carolina. I am the General Manager, Transmission Planning and Operations Strategy for Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC" and together with DEP, "Duke Energy" or the "Companies"). I am providing rebuttal testimony today with Maura Farver as the "Transmission and Solar Procurement Panel."

Q. ARE YOU THE SAME PANEL THAT FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes. Witness Farver also addresses solar procurement issues in greater detail, so we have expanded the panel name to "Transmission and Solar Procurement."

Q. IS THE PANEL INTRODUCING ANY EXHIBITS IN SUPPORT OF YOUR REBUTTAL TESTIMONY?

A. Yes. Transmission and Solar Procurement Panel Rebuttal Exhibit 1 presents Table 4-13 from Chapter 4 – Execution Plan of the Carbon Plan filed on May 16, 2022. Transmission and Solar Procurement Panel Rebuttal Exhibit 2 presents provides Rebuttal Figure 1 as presented in our rebuttal testimony in a larger, more readable format. Transmission and Solar Procurement Panel Rebuttal Exhibit 3 presents a list of the Red Zone Expansion Plan ("RZEP") projects that indicates those projects for which the Companies are seeking Commission acknowledgement of their need for execution of the Carbon Plan.

Q. MR. ROBERTS, WHAT IS THE PURPOSE OF THE TRANSMISSION AND SOLAR PROCUREMENT PANEL'S REBUTTAL TESTIMONY?

A. The purpose of this panel's rebuttal testimony is to respond to other parties' testimony related to near-term transmission related actions the Companies have indicated are imperative to pursue for executing a Carbon Plan portfolio and making progress in the Companies' continuing system-wide Carolinas energy transition consistent with North Carolina Session Law 2021-165 ("HB 951") targets.

Table 4-13 of Chapter 4 – Execution Plan, attached as Transmission Panel Rebuttal Exhibit 1, identifies five key near-term actions that are critical to immediately beginning the transmission system transformation actions necessary for successful execution of Carbon Plan resource portfolios. These actions include (modified from the original Table 4-13 to reflect current status):

1. Obtained FERC approval of a generation replacement queue process
2. Subject to Transmission Advisory Group stakeholder review and NCTPC approval of the RZEP projects, start RZEP transmission projects included in 2022 NCTPC Local Transmission Plan
3. Start preliminary routing, scoping, siting, right-of-way acquisition for offshore wind transmission projects with point of interconnection at New Bern Substation
4. Perform further Transmission Planning evaluations/studies for transmission transformation needed to facilitate coal generation retirements

5. Request interconnection studies for needed MW levels of offshore wind being injected into New Bern Substation

This Rebuttal Testimony will further demonstrate for the Commission the critical importance of these near-term transmission related actions to enable the reliable and successful execution of the Carbon Plan. Specifically, I will respond to testimony regarding the need for proactive transmission planning, the need and next steps for the RZEP projects, and address specific topics related to the injection of offshore wind into the DEP transmission system, the Companies' generator replacement process, and transmission-related modeling assumptions.

In addition, Ms. Farver addresses certain solar procurement and storage development and procurement issues raised by the Public Staff and intervenor testimony.

I. <u>PROACTIVE TRANSMISSION PLANNING AND RED ZONE EXPANSION PLAN ("RZEP") PROJECTS</u>

Q. MR. ROBERTS, DID ANY PARTY DISAGREE WITH THE COMPANIES THAT HB 951 ESTABLISHES NEW PUBLIC POLICY GOALS INCLUDING DEVELOPMENT OF A CARBON PLAN?

A. No. Public Staff Witness Metz testified that the Commission should acknowledge the public policy goals for North Carolina as part of its 2022

Carbon Plan, as the Companies request.[1] No other party opposed this request.

Q. DID OTHER PARTIES IDENTIFY PROACTIVE TRANSMISSION PLANNING AS KEY TO RELIABLY EXECUTING THE CARBON PLAN?

A. Yes. There was general recognition among the parties who testified on this matter of the need for proactive transmission planning.[2]

Q. DO YOU AGREE?

A. Yes. The reactive nature of relying on commitments in generator interconnection agreements before beginning construction of transmission network upgrades to enable new generator interconnections will not support the pace or volume of interconnecting resources necessary to implement the Carbon Plan. A proactive transmission planning approach, that is scenario-based and coordinates transmission network upgrades, greenfield transmission expansion, and explores alternatives is necessary to meet the requirements of the Carbon Plan in the specified timeframes and in a cost-effective manner.

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[1] Public Staff Metz Direct Testimony at 46-47.
[2] *See, e.g.,* Public Staff Metz Direct Testimony at 36-37; CPSA T. Norris Direct Testimony at 7; NCSEA, et al. Caspary Direct Testimony at 4-5.

Q. HOW DOES DUKE ENERGY INTEND TO NAVIGATE PROACTIVE TRANSMISSION PLANNING CONSIDERING THE POSSIBLE FERC ORDERS RESULTING FROM THE TRANSMISSION PLANNING NOPR?

A. Duke Energy will continue to engage with the Transmission Planning Notice of Proposed Rulemaking ("NOPR")[3] proceeding and will implement FERC Orders on changes to transmission planning processes in its Joint Open Access Transmission Tariff ("OATT"). Duke Energy will also engage with North Carolina Transmission Planning Collaborative ("NCTPC") Oversight/Steering Committee ("OSC") members, NCEMC, and Electricities, in reviewing and improving NCTPC Local Transmission Planning processes to include the necessary proactive planning process steps for cost-effective transmission planning for the transmission systems within DEC and DEP. In addition, DEC and DEP will continue to participate in regional planning through the Southeastern Regional Transmission Planning ("SERTP") process that will adopt FERC Orders resulting from the FERC Transmission Planning NOPR. The development of local, regional, and interregional transmission plans ensures efficient and cost-effective planning to maintain or improve reliable service to DEC and DEP customers while managing the retirement of generation and addition of new planned generation.

[3] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection,* Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).

Q. ARE THE RZEP PROJECTS A KEY EXAMPLE OF DUKE ENERGY'S COMMITMENT TO PROACTIVE PLANNING?

A. Yes. Duke Energy considers the RZEP projects to be a necessary and appropriate first step in this direction as these projects have multiple value propositions, including replacing aging infrastructure, resiliency improvements, lower impedance, thus lower transmission losses, in addition to facilitating improvement in the pace and volume of interconnection of incremental resources.

Q. ARE THE RZEP PROJECTS A KEY COMPONENT TO RELIABLE AND SUCCESSFUL EXECUTION OF THE CARBON PLAN?

A. Yes. The RZEP projects will allow for more interconnections of solar facilities in the "Red Zone," a high solar viability region of the DEC and DEP systems where development and interconnections of solar facilities have been thwarted due to extensive network transmission upgrades required. To date, these Red Zone upgrades have created insurmountable cost hurdles for developers of one or two projects being asked to bear the upfront burden of that cost.

Q. DO OTHER PARTIES AGREE WITH THE COMPANIES REGARDING THE NEED FOR THE RZEP PROJECTS?

A. Yes. There is widespread agreement among many parties, including the Public Staff, NCEMC, CPSA, CCEBA/MAREC, and NCSEA et al., that the near-term action of developing and constructing the RZEP projects is a critical path step to executing the Carbon Plan. For example, CPSA witness

Norris acknowledges in his testimony that "Duke has amply demonstrated that the RZEP upgrades are needed to achieve compliance with HB 951 and that ratepayers would be well served by the completion of those upgrades as soon as possible."[4] CCEBA and NCSEA also acknowledge the RZEP projects are necessary.[5] NCEMC witness Ragsdale "recognizes that the RZEP projects are largely designed to address transmission constraints in some of the most cost-effective and desirable locations for additional solar development in North Carolina and is committed to continuing to work with Duke to evaluate these projects through the NCTPC process." NCEMC witness Ragsdale also emphasizes that "Duke's expedited timeline for RZEP should not result in the RZEP projects being prioritized over other transmission projects needed for reliability and maintaining service quality for retail and wholesale customers."[6] Duke Energy agrees with NCEMC witness Ragsdale on this point and will continue to engage with affected systems in the context of generator interconnections as contemplated in the OATT.

[4] CPSA Norris Direct Testimony at 7.
[5] CCEBA/MAREC Gonatas Direct Testimony at 18-20; NCSEA et al. Caspary Direct Testimony at 13-14.
[6] NCEMC Ragsdale Direct Testimony at 5.

Q. WHAT ARE THE PUBLIC STAFF'S SPECIFIC RECOMMENDATIONS WITH RESPECT TO THE RED ZONE PROJECTS AND SUPPLEMENTAL STUDIES?

A. The Public Staff is generally supportive of the supplemental studies and supports Commission acknowledgment of the majority of the RZEP projects. Witness Metz states that the three DEP projects identified by this Panel in its direct testimony that did not demonstrate strong solar dependence (project #s 9, 11, and 12)[7] should be delayed at this time.[8]

In addition, witness Metz recommends the Companies delay an additional three RZEP projects. For DEC, he does not recommend DEC proactively build RZEP project #4 (Clinton 100 kV, Bush River-Laurens) at this time, "based on the relatively few generator facilities impacting that line and the unclear causal relationship between future solar generation and this upgrade."[9] At the same time, witness Metz recognizes that "this potential line upgrade will likely be needed in the near future if solar generation continues to attempt to interconnect in this area given its proximity to other transmission projects in question."[10]

For DEP, witness Metz recommends DEP RZEP projects #7 and 14 (the Erwin-Fayetteville 115 kV line and the Camden-Camden Dupont 115 kV line) be removed from the Red Zone Expansion Plan at this time, noting

[7] The numbers associated with the RZEP projects correspond to the order of projects listed at Table P-3 of Appendix P.
[8] *Id.* at 44.
[9] *Id.* at 42.
[10] *Id.* at 42.

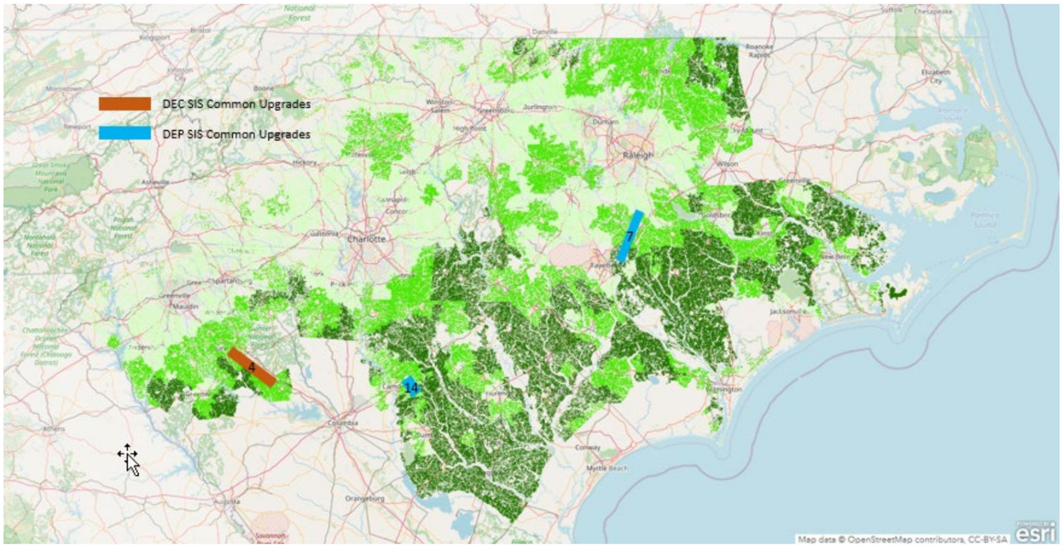
that these projects "have approximately 25% of all common upgrades affecting the proposed transmission projects in the study," and that project #14 "appears relatively small in scope compared to the other transmission upgrades."[11] Similar to his DEC recommendation, witness Metz asks the Companies to discuss the impact of delaying these projects on reliability and cost effectiveness and provide any additional support for the need for these projects.

Q. ARE THESE THREE LINES LOCATED WITHIN THE HIGH SOLAR VIABILITY RED ZONE AREAS?

A. Yes. Rebuttal Figure 1 below presents a map that shows the overlapping proximity of the projects that the Public Staff recommends not building at this time—DEC project #4 and DEP projects #7 and #14—with the high solar viability areas in DEC and DEP.

[11] *Id.* at 44.

Rebuttal Figure 1 – RZEP Projects #4, #7, and #14 Overlaid with High Solar Viability Areas[12]



Q. DO YOU AGREE WITH THE PUBLIC STAFF'S RECOMMENDATION THAT AN ADDITIONAL THREE RZEP PROJECTS NOT BE PURSUED AT THIS TIME?

A. I do not agree with the Public Staff recommendations with respect to two of these projects. The results from prior generator interconnection studies and the supplemental studies demonstrate that the Clinton 100 kV B/W lines and Erwin – Fayetteville 115 kV line will be necessary to integrate hundreds of MW of generation in the red zone area and provide a clear causal relationship between the incremental addition of generation in this high solar viability region and the need for these network upgrades.

[12] Rebuttal Figure 1 is also replicated in Transmission and Solar Procurement Panel Rebuttal Exhibit 2.

Specifically, the RZEP mapping of prior generator interconnection studies (Exhibit 1 of the Transmission Panel Direct Testimony) reflects the Clinton 100 kV Black/White lines in DEC's red zone have over 428 MW of solar facilities mapped to needing this network upgrade and the DEC supplemental study (Exhibit 3 of the Transmission Panel Direct Testimony) reflects the Clinton 100 kV B/W lines had the DFax threshold and/or the line Loading Impact[13] threshold exceeded for approximately 740 MW of solar facilities considered in the study.

The DEP RZEP mapping of prior generator interconnection studies (Exhibit 2 of the Transmission Panel Direct Testimony) reflects the Erwin – Fayetteville 115 kV line in DEP's red zone has over 734 MW of solar facilities mapped to needing this network upgrade in the Transitional Cluster Study alone. The DEP supplemental study (Exhibit 4 of the Transmission Panel Direct Testimony) reflects the Erwin – Fayetteville 115 kV line had the DFax threshold and/or the line Loading Impact threshold exceeded for approximately 625 MW of solar facilities considered in the study.

While Duke Energy agrees that Project #14—the Camden–Camden Dupont 115 kV line upgrade—may be able to be postponed at this time,

[13] **MW Output** = Real power output of the generator
Distribution Factor (DFax): The proportion of a generator's MW Output that flows on a transmission facility under the worst contingency – DFax threshold = 3%
MW Impact = MW Output x DFax
Loading Impact = MW Impact / Facility Rating – Loading Impact threshold = 1%.

Duke Energy will pay close attention to this upgrade being needed in the near-term if identified in the 2022 DISIS Phase 1 Study.

Q. WITNESS METZ ASKED THE COMPANIES TO IDENTIFY ANY CONSTRUCTION EFFICIENCIES OR COST SAVINGS ASSOCIATED WITH PROACTIVELY CONSTRUCTING ANY OF THE PROPOSED RZEP PROJECTS THAT ARE NOT SUPPORTED BY PUBLIC STAFF'S INITIAL REVIEW. PLEASE RESPOND.

A. As noted in the DEC Transitional Cluster Study report,[14] the upgrade of sections of the Clinton 100 kV B/W lines is estimated to take 48 months. If smaller generators are able to interconnect with sections of the Clinton 100 kV B/W lines prior to constructing the RZEP upgrades, additional cost could be incurred through the need for temporary line construction not contemplated in the current project scope. The DEP Transitional Cluster Study Report reflects that it would take 54 months to upgrade the Erwin – Fayetteville 115 kV line.[15] Even though DEP plans to accelerate this schedule, if delayed and outages need to be scheduled beyond 2026 that would be competing for the same outage window needed for implementing the upgrade to the Erwin-Fayetteville 115 kV line, this delay in the upgrade schedule could delay interconnecting generators dependent on this RZEP

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[14] Duke Energy Carolinas, LLC Transitional Cluster Study Phase 1 Report at 20 (Feb. 28, 2022), *available at* https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/2022-02-28_DEC_TC_Phase_1_Study_Report.pdf.

[15] Duke Energy Progress, LLC Transitional Cluster Study Phase 1 Report at 14 (Feb. 28, 2022) https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/2022-02-28_DEP_TC_Phase_1_Study_Report.pdf.

upgrade. Thus, the Clinton 100 kV B/W lines and the Erwin – Fayetteville 115 kV line should remain in the list of RZEP projects for which the Companies are requesting Commission acknowledgement that they are necessary for executing Carbon Plan portfolios at this time.

Q. WITNESS METZ ALSO ASKED THAT THE COMPANIES CONFIRM HIS UNDERSTANDING OF NEXT STEPS IN THE NCTPC PROCESS FOR DETERMINING PROACTIVE UPGRADES AND INCLUDING THE RZEP IN THE NCTPC LOCAL TRANSMISSION PLAN.[16] PLEASE RESPOND.

A. As stated in this Panel's direct testimony, the next steps in the NCTPC process for incorporating the RZEP projects are to: 1) present the updated status of the RZEP projects to the Transmission Advisory Group ("TAG") stakeholders and receive feedback/input on the projects, and 2) seek approval from the NCTPC to include the RZEP projects in the 2022 Local Transmission Plan, all in accordance with the FERC-approved Local Transmission Planning Process as described in Attachment N-1 of the OATT. The Commission's acknowledgement that the proposed RZEP projects are needed to interconnect new solar generating facilities and necessary for execution of the Carbon Plan would bolster the position that the RZEP projects need to be included in the 2022 NCTPC Local Transmission Plan.

[16] Public Staff Metz Direct Testimony at 46-47.

Q. WHY SHOULD THE COMMISSION ACKNOWLEDGE THE RZEP PROJECTS AS NECESSARY FOR EXECUTION OF THE CARBON PLAN?

A. In its June 10, 2022, 2022 Solar Procurement Order, the Commission directed Duke Energy not to include RZEP projects in the 2022 DISIS baseline, concluding that doing so would be premature based on its finding that "no party has presented competent evidence that the RZEP projects are necessary to achieve the Carbon Plan."[17] The Commission encouraged Duke Energy and any intervenor supporting the RZEP "to provide substantial evidence supporting the necessity of the RZEP projects to achieve the goals of the Carbon Plan in that proceeding."[18] In response to the Commission's order, the Companies conducted supplemental studies to provide substantial evidence of the necessity of the RZEP projects to achieve the goals of the Carbon Plan. The results of these supplemental studies are included in this Panel's direct testimony. Given the Commission's directives in the 2022 Solar Procurement Order, the Companies are therefore seeking Commission acknowledgement that there is substantial evidence demonstrating the need for the RZEP projects for implementation of Carbon Plan portfolios.

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[17] *In the Matter of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Solar Procurement Pursuant to Session Law 2021-165, Section 2.(c)*, Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments at 7, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (Jun. 10, 2022) ("2022 Solar Procurement Order").
[18] *Id.*

Q. MR. ROBERTS, IS THERE AN UPDATED LIST OF RZEP PROJECTS THAT DUKE ENERGY REQUESTS THE COMMISSION ACKNOWLEDGE AS NEEDED IN THIS INITIAL CARBON PLAN?

A. Yes. Transmission and Solar Procurement Panel Rebuttal Exhibit 3 presents the list of RZEP projects that Duke Energy requests the Commission acknowledge in approving this initial Carbon Plan.

Q. WHAT ARE DUKE ENERGY'S NEXT STEPS IF THE COMMISSION DOES NOT ACKNOWLEDGE THAT THE RZEP PROJECTS PRESENTED IN REBUTTAL EXHIBIT 3 ARE NECESSARY FOR EXECUTION OF THE CARBON PLAN?

A. Duke Energy continues to believe that all of the originally identified RZEP projects are necessary to interconnect the volumes of solar needed to meet HB 951 targets and progress the system-wide Carolinas energy transition. As shown in the Transmission Panel direct testimony, the supplemental studies provide evidence of the need for 15 of the original 18 RZEP projects for initial procurements of solar to be interconnected by 2030. However, past transmission planning studies have shown these three upgrades to be needed for interconnecting solar projects, and the Companies continue to view them as needed.

The Public Staff recommends that DEC and DEP not move forward at this time with constructing three of the 15 projects supported by the supplemental studies. The Companies respectfully disagree with this recommendation for two of those three projects (the Clinton 100kV B/W lines and the Erwin – Fayetteville 115kV line). The Companies acknowledge that Project #14, the Camden-Camden Dupont 115 kV line upgrade, may be able to be postponed at this time, but nevertheless continue to believe that this project will be necessary for timely execution of the Carbon Plan.

As I discussed above, the request for the Commission to acknowledge the need for the RZEP is driven by the Commission's directives in the 2022 Solar Procurement Order and the Companies' desire to confirm that it has satisfied that directive. However, regardless of the outcome of the Commission's acknowledgement of the RZEP projects being necessary, the Companies will continue to iteratively evaluate through the NCTPC the need for and benefits of proactive transmission planning projects to interconnect new generation, enable coal unit retirements as part of the system-wide Carolinas energy transition and to implement the public policy requirements of HB 951. In doing so, the Companies will continue to follow the procedures in its OATT for approval of transmission projects for inclusion in its Local Transmission Plan.

II. TRANSMISSION PLANNING FOR OFFSHORE WIND

Q. HOW DO YOU RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION THAT THE COMMISSION DENY DUKE'S REQUEST TO BEGIN NEAR-TERM RESOURCE DEVELOPMENT ACTIVITIES FOR OFFSHORE WIND?

A. Whether, how much, and when offshore wind generation is needed to achieve the Carbon Plan is beyond the scope of my responsibilities. However, for the avoidance of doubt, the Companies need to immediately start preliminary routing, scoping, siting, and right-of-way acquisition for offshore wind transmission projects with the point of interconnection at the New Bern Substation in order to meet an in-service date that facilitates bringing offshore wind energy into the DEP system by 2030. Delaying these activities to 2024 or beyond means the transmission infrastructure will have a later in-service date and thus, the ability to bring offshore wind energy into the DEP system will be delayed beyond 2030. Furthermore, constructing the transmission needed to interconnect offshore wind has substantial execution risk and 2030 is already expected to be very challenging to achieve.

Q. HOW DO YOU RESPOND TO AVANGRID'S ASSERTION THAT COST EFFECTIVE INJECTIONS OF OFFSHORE WIND OF 1.3 GW ARE POSSIBLE AT EITHER THE HAVELOCK OR NEW BERN POINTS OF INTERCONNECTION WITHOUT 500 KV UPGRADES?

A. Avangrid witnesses Starrett and Gallagher claim that 1.3 GW of offshore wind can be delivered even without the 500 kV grid expansion considered in the Carbon Plan. First, they state Duke Energy's proposal to interconnect at New Bern burdens the first offshore wind projects with this nearly $1 billion cost of this expansion, implying it is a requirement for success. This assertion is not correct. Based upon preliminary transmission planning screening analysis and as addressed in Appendix P (Transmission Planning and Grid Transformation), Duke Energy assumes in the Carbon Plan that an 800 MW offshore wind resource does not include any 500 kV expansion.[19] However, at 1,600 MW and above, Duke Energy's modeling assumes a 500 kV expansion is needed to reliably transfer offshore wind energy into the DEP system.

Further, as stated in this Panel's direct testimony, New Bern is expected to be a superior and less costly injection point than Havelock. The Havelock 230 substation has only three 230 kV lines connected, one of

[19] Carbon Plan Appendix P at 18 ("The screening studies performed to date as part of the 2020 NCTPC study have indicated that 800 MW of offshore wind can be injected at New Bern 230 kV without the addition of major new network transmission lines but with some significant upgrades to the existing system in the New Bern area.").

which goes east to the peninsula-type area of Morehead City. Extensive 230 kV upgrades would likely be needed to accommodate 1.3 GW of energy injection considering the approximate 2,600 MW of generation just to the south at DEP's Brunswick Nuclear Station and Sutton Plant and the nearby solar facilities. In contrast, the New Bern 230 kV substation has five 230 kV lines connected and injecting 1.3 GW of offshore wind energy into the New Bern 230 kV substation could well be possible without any 500 kV expansion. That amount of power injection into New Bern would still likely not be as simple as Avangrid seems to suggest. Several factors would influence the actual network upgrades needed, including considering the nearby generation from Brunswick Nuclear Station, Sutton Plant, Lee Energy Complex, and solar facilities at full output to ensure retention of firm deliverability of that generation during a summer peak study.

Also, as noted in the 2020 NCTPC Offshore Wind Study Report, "No other generation from the DEC, DEP, or PJM generator interconnection queues was added. These generator interconnection queues contain thousands of MW of possible generation that may or may not actually interconnect and which could significantly affect the flows on the DEC, DEP, and Dominion transmission systems in unknown ways. The results of this study could change significantly depending on which and how much generation in those queues moves forward to interconnection."[20] As shown at Figure 2: 2022 DISIS Red-Zone Map from the Transmission Panel Direct Testimony, there are several solar facilities requesting interconnection in the counties in close proximity to the Havelock and New Bern area that could easily influence the network transmission upgrade needs for injecting offshore wind into the Havelock/New Bern area.

Q. HAS AVANGRID SUBMITTED A GENERATOR INTERCONECTION REQUEST TO DEP?

A. No. While Avangrid is taking steps to perform due diligence, including assessing the potential transmission costs to interconnect its proposed project, the only way to definitively know what transmission network upgrades would be required for a given amount of offshore wind, whether 800 MW, 1,300 MW, 1,600 MW, or 2,400 MW injected into the Havelock/New Bern area is through a formal generator interconnection request and subsequent Phase 1 and Phase 2 generator interconnection cluster studies.

[20] Report on the NCTPC 2020 Offshore Wind Study at 1 (Jun. 7, 2021), *available at* http://www.nctpc.org/nctpc/document/REF/2021-06-07/W_Doc/2020_NCTPC_Offshore_Wind_Report_06_07_2021-FINAL%20Rev%202.pdf.

III. GENERATOR REPLACEMENT

Q. PLEASE UPDATE THE COMMISSION ON THE STATUS OF THE COMPANIES' GENERATOR REPLACEMENT REQUEST TO FERC.

A. FERC approved the Companies' generator replacement proposal on September 6, 2022.[21] FERC approval of the generator replacement interconnection study process is a key initial accomplishment in the Companies' execution plan.

Q. GIVEN FERC'S APPROVAL OF THE COMPANIES' GENERATOR REPLACEMENT PROCESS, WHAT ARE THE COMPANIES' NEXT STEPS?

A. The Companies have already contracted with a Generation Replacement Coordinator ("GRC") as an independent entity to conduct generation replacement request studies. These contracts were submitted as part of the DEC and DEP Generator Replacement filing and were included in the FERC Order accepting the Tariff Provisions. The FERC-approved process is part of the OATT posted on the DEC and DEP OASIS sites. The administrative processes for receiving requests, the GRC access to retrieving study base cases, and communications protocols with generation replacement customers are being established and should be in place by

[21] *Duke Energy Carolinas, LLC, et al.*, 180 FERC ¶ 61,156 (2022).

October 2022 to facilitate the start of receiving and processing generation replacement requests.

Q. WHY DO THE COMPANIES VIEW A FERC-APPROVED GENERATION REPLACEMENT PROCESS AS A KEY NEAR-TERM ACTION?

A. As stated in the Transmission Panel direct testimony, a generator replacement process will be critical to efficient, timely, and cost-effective replacement of existing coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located. Utilization of the same switchyard for interconnection will save the cost of potentially expensive interconnection facilities and potential network upgrades that would be required if the same replacement generation was constructed at a greenfield site.

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS METZ'S TESTIMONY ON THIS TOPIC?

A. The Companies agree with the Public Staff's perspective on this issue.[22] The generation replacement process should not be used blindly just because it can keep transmission network upgrade costs low; any generation replacement resource needs to be evaluated holistically considering location, resource capital and production costs, associated transmission costs, and reliability considerations. Based on past IRP comments and input

[22] Public Staff Metz Direct Testimony at 48-49.

from the Commission, this is the manner in which the Companies are evaluating resources for capacity expansion planning for selecting resources for the Carbon Plan. That said, the Companies do view the generation replacement process as providing a valuable tool for evaluating potential generation replacement options to facilitate coal generation retirements and achieving the most cost-effective and reliable option for customers.

IV. TRANSMISSION RELATED MODELING ISSUES

Q. DO YOU HAVE ANY RESPONSES TO TRANSMISSION RELATED MODELING ISSUES RAISED BY INTERVENORS?

A. Yes. CPSA raised a number of arguments regarding modeling issues to which transmission is closely related. In this section of our rebuttal, I will provide a transmission perspective on these issues, to further support the rebuttal testimony of the Modeling and Near-Term Actions Panel.

A. Solar Interconnection Constraint

Q. HOW DO YOU RESPOND TO THE TESTIMONY OF CPSA'S WITNESSES REGARDING THE COMPANIES' SOLAR INTERCONNECTION MODELING ASSUMPTIONS?

A. CPSA's witnesses Norris and Watts contend that the Companies' planning assumptions forecasting future solar interconnections in the Carbon Plan modeling impose unreasonable constraints on solar. As the Modeling and Near-Term Actions Panel demonstrates, those contentions are not informed by the specific considerations of the DEC and DEP systems and interconnection procedures. My testimony provides additional detail and support for these constraints from a transmission perspective.

Q. CPSA WITNESS WATTS CLAIMS THAT THE COMPANIES' MODELING ASSUMPTIONS WITH RESPECT TO SOLAR INTERCONNECTIONS ARE CONSERVATIVE, AND THAT INTERCONNECTING 20 TO 21 NEW SOLAR GENERATING FACILITIES TO THE COMPANIES' TRANSMISSION SYSTEMS, YIELDING 1,800 MW/YEAR, "SHOULD BE COMFORTABLY ACHIEVABLE."[23] DO YOU AGREE WITH HIS ASSESSMENTS?

A. No. Witness Watts bases his statement on the observation that Duke Energy interconnected approximately 750 MW of new solar in 2015 and 2017. Ninety percent or greater of those projects were distribution level connections, which are significantly less complex because they do not require transmission outages to connect, and the interconnection facilities are significantly smaller than transmission interconnection facilities. The time to connect from signing the interconnection agreement to commercial operation was less than a year for a distribution level project versus 26-32 months currently for transmission level projects. Furthermore, the ability to interconnect solar facilities to the Companies' systems without extensive transmission network upgrades (*i.e.*, the "low hanging fruit") has occurred with the 4+ GW of solar already interconnected. Public Staff witness Metz

[23] CPSA Watts Direct Testimony at 14.

recognizes this diminishing ability to interconnect additional resources to the Companies' systems without additional transmission system expansion.[24] As shown in Figure 15 in the Modeling Panel Direct Testimony, the Companies believe that 14 to 15 interconnections can likely be achieved in the near-term. From a transmission perspective, this is a reasonable but aggressive target. However, based upon my detailed knowledge of the Companies' transmission system and extensive familiarity with the Red Zone constraints, it is my opinion that it would be very difficult, and possibly unachievable, to make 20 to 21 interconnections in a year from an outage and other transmission constraints viewpoint.

As past manager of the DEP transmission outage coordination group, one of the biggest constraints for the pace of solar interconnections looking to the future is that transmission line outages are needed to construct the interconnection facilities and transmission network upgrades needed to interconnect resources. First, the interconnection facilities alone, such as installing isolation line switches and transfer trip relay protection, require a five-week outage that could be longer if the transmission line needs to be raised to accommodate the isolation line switches or if the resource is connecting to a 230 kV line that requires a new ring bus. Second, the outages for constructing network upgrades and interconnection facilities must be coordinated such that customer and system reliability is not

[24] Public Staff Metz Direct Testimony at 38.

jeopardized during the outages. Third, additional transmission outages that must be coordinated and planned include outages for NERC relay preventive maintenance procedures, asset management outages to replace aging infrastructure, transmission maintenance outages, outages to construct and connect new retail and wholesale points of delivery, and all of these outages must be coordinated and planned such that reliability is maintained considering a contingency/forced outage of a transmission or generation asset. Fourth, due to the Carolinas peak demand summer and winter seasons, most outages are limited to occurring in the spring and fall. Fifth, the weather needs to cooperate. Hurricanes, tornadoes, high winds, heavy rains, and associated restoration activities can thwart outage work schedules, which leads to new outage coordination efforts and rescheduling and re-prioritization of work that can delay in-service dates. Finally, supply chain considerations can still upset the best laid plans, though Duke Energy will leverage the forward-looking benefits of proactive transmission planning to secure supplies needed for construction in a timely manner.

Q. WILL PROACTIVELY CONSTRUCTING THE RZEP PROJECTS HELP INTERCONNECT MORE SOLAR GENERATION?

A. Yes. Installing the RZEP projects is key to meeting interconnection targets and longer term will relieve constraints and enable new solar interconnections. As shown in the Modeling and Near-Term Action Panel's Testimony, the number of annual transmission interconnections must be executable and will improve as RZEP projects are completed. If the RZEP projects can be placed in-service on an accelerated schedule and interconnection process improvements are identified and implemented, annual solar procurements and interconnections may be able to be increased. However, the Companies will need to continue to be confident that the planned number of interconnections can be executed in the timeframe required given the aforementioned hurdles with outage coordination.

Q. WHAT IS YOUR RESPONSE TO WITNESS WATTS' ASSERTION THAT DUKE SHOULD ENCOURAGE THIRD-PARTY SELF-BUILD OF INTERCONNECTION FACILITIES AND STAND-ALONE NETWORK UPGRADES?[25]

A. Based on Duke Energy's interconnection standards,[26] a transmission connected solar facility, if connected to a networked 100 kV or 115 kV transmission line, must have line switches installed on both sides of the point of interconnection for isolation purposes if a line switch is not already installed on the line within one mile of the tap line. If certain criteria are not met for 230 kV interconnections, a multi-breaker station is recommended. Duke Energy would also need to connect the interconnection infrastructure to the DEC or DEP system and modify associated relaying. These steps in the interconnection process require on average a five-week transmission

[25] CPSA Watts Direct Testimony at 10-11.
[26] Susbstation Configuration Guideline for Transmission Inverter Based Interconnections, https://www.oasis.oati.com/woa/docs/DUK/DUKdocs/GDLF-EGR-TRM-00004_Rev_1_ Substation_Configuration_Guideline_for_Interconnections_OASIS_v1.pdf (last visited Sept. 9, 2022).

line outage. Thus, connection of a solar facility to a 100 kV, 115 kV, or 230 kV line requires a coordinated transmission line outage on the DEC or DEP system, as shown by Figure 5 in the Transmission Panel Direct Testimony. Because of this impact to day-to-day transmission operations, reliance on third-party construction introduces significant reliability risk. In fact, the DEC and DEP OATT and the modifications required by FERC Order No. 845 acknowledged this distinction, providing the option for interconnection customers to build interconnection facilities and stand-alone network upgrades, not network upgrades that risk adverse reliability impacts.

Q. HOW DO YOU RESPOND TO WITNESS WATTS' CONTENTION THAT DUKE'S INTERCONNECTION STUDY CRITERIA GO BEYOND NERC REQUIREMENTS, AND THAT REVISING DUKE'S CRITERIA COULD REDUCE THE NEED FOR NEW INFRASTRUCTURE, RESULTING IN SHORTER INTERCONNECTION TIMES?[27]

A. I disagree, and I also do not believe this is the appropriate forum to be debating NERC reliability standards. The NERC reliability standards, as stated on the NERC website, define the reliability requirements for planning and operating the North American bulk power system, and are developed

[27] CPSA Watts Direct Testimony at 16-17.

using a results-based approach that focuses on performance, risk management, and entity capabilities. TPL-001-4 establishes Transmission system planning performance requirements to ensure a Bulk Electric System that operates reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies. Within this standard, the P3 (Multiple Contingency) category is triggered by the "loss of generator unit followed by System adjustments." "System adjustments" is not a defined term in the NERC Glossary of Terms, and nowhere does the TPL-001-4 Standard state that a System adjustments period is intended to represent a short-term operating condition until the initial generator unit can be restored with reliability as the primary focus.

For reliable transmission planning, Duke Energy does not limit the initial generator outage duration in hopes that the contingent generator represents a "short-term operating condition." It is thus prudent to plan for the System adjustment to redispatch generation economically to prepare for the next contingency, ensure reliability, and lower production costs. In addition, this planning practice is prudent because it resets the system for the system operator to develop a reliable operating plan per NERC Reliability Standards TOP-001 and TOP-002 that can be implemented in a timely manner to respond to the next contingency.

Q. HOW DO YOU RESPOND TO CPSA'S CLAIM OF A LACK OF STAKEHOLDER OUTREACH WITH RESPECT TO THE INTERCONNECTION PROCESS IMPROVEMENT INITIATIVE THAT DUKE ENERGY MENTIONS IN ITS TRAANSMISSION PANEL DIRECT TESTIMONY?[28]

A. Duke Energy has interconnected an extraordinary amount of solar within the DEC and DEP systems and continues to work to create efficiencies and pathways for interconnecting increasing amounts of solar for execution of the Carbon Plan. Duke Energy presented this process improvement initiative at the Duke Energy Carolinas Carbon Plan Technical Subgroup Meeting Virtual Meeting on February 18, 2022. Through continued interconnection process efficiency refinements as well as implementation of RZEP projects, the pace of solar interconnections should see an improving trend through 2030 and beyond. This is a key area of focus for Duke Energy as we recognize—and are planning for—achieving an increasing pace of solar interconnections to the Companies' transmission system over the next decade to execute the Carbon Plan while ensuring reliability is maintained for our customers.

[28] CPSA Watts Direct Testimony at 15-16.

B. Transmission Cost Adders

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANIES' PROPOSED TRANSMISSION COST ADDERS AS UTILIZED IN THE CARBON PLAN MODELING?

A. Yes. Public Staff witness Thomas states that the adders are reasonable for planning purposes.[29]

Q. DID ANY OTHER PARTY OPPOSE THE PROPOSED TRANSMISSION COST ADDERS?

A. No. No other party directly addressed the Companies' proposed adders.

C. Imports/Transfer Limits

Q. WHAT IS YOUR RESPONSE TO TECH CUSTOMERS WITNESS BORGATTI'S CLAIM THAT THE COMPANIES DO NOT CONSIDER RENEWABLE IMPORTS FROM NEIGHBORING INTERFACES ASIDE FROM PJM?[30]

A. As stated in the Transmission Panel Direct Testimony, Duke Energy is not shutting the door on the potential for acquiring Midwest onshore wind based on the results of our internal study of imports from PJM. Duke Energy has submitted a 1,000 MW firm transmission service request ("TSR") to the PJM queue and is awaiting results. The results of this TSR study will be considered in future iterations of the Carbon Plan. For the avoidance of doubt, Duke Energy would plan to acquire any such off-system onshore

[29] Public Staff Thomas Direct Testimony at 55-56.
[30] Tech Customers Borgatti Direct Testimony at 25-26.

wind energy facility selected by the Commission, consistent with the Ownership Requirements under HB 951 as well as the manner in which the Carbon Plan models this asset for DEC.

Also, with respect to purchasing energy over other interfaces with DEC and DEP, through the Southeast Energy Exchange Market, the Companies can use as-available non-firm transmission service to purchase economic energy from neighboring entities to the south and to the west of the DEC and DEP systems.

Q. HOW DO YOU RESPOND TO CCEBA/MAREC WITNESS GONATAS' ASSERTIONS REGARDING THE COMPANIES' TRANSFER LIMITATIONS?[31]

A. DEC and DEP transfer significant amounts of energy between the two systems daily. DEP purchases 1,600 MW of capacity from independent power producers that use the DEC/DEP interface, thus the reason that firm import capability from DEC to DEP is currently limited. Wholesale customers utilize the DEC/DEP interface to transfer power from one system to the other for serving wholesale load. However, the biggest utilization of the DEC/DEP interface is through the Joint Dispatch Agreement. This Joint Dispatch dynamic schedule transferred over 6.1 million MWh, and 3.8 million MWh of economic energy between the two systems in 2021 and 2022 (through June) respectively. Also, the maximum hourly transfer of

[31] CCEBA/MAREC Gonatas Direct Testimony at 7-12.

economic energy between the two systems was over 3,000 MWh and 2,900 MWh for the same time periods, indicating the DEC/DEP interface is healthy and utilized. Furthermore, as discussed in the Carbon Plan and further addressed in the direct testimony of Nelson Peeler and Laura Bateman on the Carolinas Utilities Operations Panel, this interface is planned to be absorbed into a single transmission zone in the future through consolidated system operations or a merger. Transmission planning for this single transmission zone will ensure reliable and economic transfers of energy are planned for across the zone.

Q. WITH RESPECT TO REGIONAL AND INTERREGIONAL STUDIES IN WHICH DEC AND DEP PARTICIPATE, CAN YOU INDICATE FOR CCEBA/MAREC WITNESS GONATAS WHICH GROUPS CONDUCT THOSE TYPES OF STUDIES?

A. Yes. As provided in Attachment N-1 of the Companies' OATT in compliance with FERC Order Nos. 890 and 1000, and as described extensively in Appendix P of the Carbon Plan, DEC and DEP participate in the NCTPC for Local Transmission Planning of the local transmission systems including the DEC and DEP transmission systems in North Carolina and South Carolina. DEC and DEP Transmission Planning also participate in Regional and Inter-regional Transmission Planning studies through SERTP.

As discussed in Appendix P, in addition to the local, regional, and inter-regional processes outlined in the OATT and required by FERC, the

Companies also participate in a number of other regional working groups, including the Carolinas Transmission Coordination Arrangement, SERC Intra-Regional Long-Term Power Flow Working Group, SERC Near-Term Power Flow Working Group, Eastern Interconnection Planning Collaborative, and the Eastern Interconnection Reliability Assessment Group.

V. SOLAR PROCUREMENT AND STORAGE DEVELOPMENT AND PROCUREMENT ISSUES

A. Solar Paired With Storage

Q. MS. FARVER, PLEASE COMMENT GENERALLY ON THE COMPANIES' EXPERIENCE WITH ADMINISTERING SOLAR PROCUREMENTS.

A. Through CPRE and now the 2022 Solar Procurement under HB 951, the Companies have gained extensive experience working with market participants and the Public Staff under the Commission's oversight to develop structured solar procurements that have delivered benefits to customers. Based on that work, there is now a strong foundation of established practices and structure (*e.g.*, evaluation practices, bid documents, contract forms) on which to build in the future. In my current role, I was responsible for designing and implementing the 2022 Solar Procurement and routinely engage with market participants to hear their perspectives on how to continue to evolve the Companies' solar procurement processes. Looking forward, the Companies are proposing substantial near-term procurements of solar and solar paired with storage in procurement events starting in 2023.

Q. CCEBA AND THE PUBLIC STAFF OFFERED TESTIMONY WITH REGARD TO THE COMPANIES' FUTURE SOLAR AND SOLAR PAIRED WITH STORAGE PROCUREMENT.[32] PLEASE SUMMARIZE THE COMPANIES' PLANS FOR FUTURE PROCUREMENT OF SOLAR PAIRED WITH STORAGE.

A. Building on the strong foundation discussed above and consistent with the Companies' recommended near-term procurements, the Companies plan to solicit both solar and solar paired with storage resources in future procurements starting in 2023 (in addition to the 2022 Solar Procurement that is already in flight).

Q. WHAT IS THE MOST SUBSTANTIAL HURDLE FACED AS THE COMPANIES LOOK TOWARDS THE COMMENCEMENT OF THE PROCUREMENT OF SOLAR PAIRED WITH STORAGE?

A. The most substantial hurdle will be the development of new contractual structures for solar paired with storage. While the PPAs for solar-only projects are well developed based on prior procurements, it will be necessary to develop substantially new contract forms to facilitate the purchase of output from third-party owned solar facilities that are paired with storage that meets the HB 951 requirement to be dispatched, operated,

[32] CCEBA DiFelice Direct Testimony at 20-24; Public Staff Thomas Direct Testimony at 52-53.

and controlled "in the same manner as the utility's own generating resources."

Q. PLEASE COMMENT ON THE CRITICAL IMPORTANCE OF THOSE CONTRACTS.

A. In the case of utility-owned resources, the Companies will have complete operating control of the facilities and will be able to operate them as needed over the life of the asset to maximize the benefits to customers. The Companies will therefore have unlimited discretion to adjust operation over time as technology and system conditions evolve in ways that are foreseeable and in other ways that are not foreseeable.

However, in the case of third-party owned facilities, the Companies' ability to operate such facilities will be controlled by the terms of the contract, which may have a contract term of 20 or 25 years. Given the fact that the operation of substantial amounts of solar paired with storage is new to the Duke Energy system and the fact that such resources will be in operation for such a long time horizon, it is crucial to ensure that the contract governing these assets provides the appropriate structure that will allow the Companies to maximize the value of the assets not just in the short-term but also in the future as system conditions change and technology evolves. There is significant complexity in establishing fair compensation structures for project owners that also properly incentivize production and require high performance of the resources. The contract terms and pricing should be designed to enable the Companies to maximize the benefits from the solar plus storage over the full contract term at a price that is fair to customers and protects them from overpayment. In addition, the contracts must provide adequate risk adjusted revenue to the project owner to enable them to attract capital to finance the projects. Reaching an appropriate balance between these objectives will require collaboration and compromise.

Q. WHAT ARE THE COMPANIES' PLANNED NEXT STEPS IN THIS RESPECT?

A. The Companies plan to engage stakeholders with respect to such contract development in advance of the 2023 procurement. We are currently targeted to start that engagement in the fourth quarter of this year.

Q. DO YOU AGREE WITH CCEBA WITNESS DiFELICE THAT THE COMMISSION SHOULD DIRECT ALL FUTURE SOLAR PROCUREMENTS TO BE FOR ONLY SOLAR PAIRED WITH STORAGE RESOURCES AND EXCLUDE SOLAR ONLY RESOURCES?[33]

A. No. The Commission should not preemptively exclude a low-cost carbon-free technology like solar-only resources from future procurements. It is premature at this time to rule out the potential value, benefits, and savings to customers of solar-only generators. To be clear, the Companies are planning for a significant portion of new solar resources procured in future procurements to include storage of potentially varying configurations. The

[33] CCEBA DiFelice Direct Testimony at 20.

Modeling and Near-Term Actions Panel also addresses this issue from a modeling perspective and highlights that the Companies would need to procure 1,200 MW of solar paired with storage in 2023-2024 to reach the 600 MW paired storage target in the near-term action plan, assuming all future solar paired with storage includes storage that is 50% of the solar nameplate capacity.

B. Standalone Storage Procurement

Q. TURNING NOW TO STANDALONE STORAGE, DO YOU BELIEVE THAT PROCUREMENT OF STANDALONE STORAGE SHOULD FOLLOW THE EXACT SAME CONSTRUCT AS THE PROCUREMENT OF SOLAR AND SOLAR PAIRED WITH STORAGE?

A. No. For the reasons explained further below, I do not believe that standalone storage should be procured in the same manner as solar and solar paired with storage.

Q. DO THE COMPANIES USE COMPETITIVE SOURCING FOR THEIR DEVELOPMENT OF STANDALONE STORAGE?[34]

A. Yes, the Companies regularly use competitive sourcing opportunities for standalone storage projects, such as RFPs for engineering, procurement, and construction ("EPC") offers and for equipment and materials. This process ensures low costs for customers through market competition.

[34] *See* CCEBA DiFelice Direct Testimony at 21.

Q. PLEASE DIFFERENTIATE BETWEEN EPC THAT THE COMPANIES ROUTINELY USE FOR STANDALONE STORAGE AS OPPOSED TO THE BUSINESS MODEL OF "THIRD-PARTY DEVELOPERS."

A. The EPC companies that the Companies routinely use for standalone storage offer a core competency in the engineering, procurement, and construction of projects. (Third-Party Developers also typically use an EPC.) Generally, the EPC companies do not perform the early-stage activities of battery development, such as handling project identification or evaluation, buying/selling any of the land, preparing engineering designs or interconnection agreements, obtaining permits, or establishing off-take sales agreements associated with new construction battery projects. An EPC company's role generally begins after these early-stage activities have been completed.

In contrast, a third-party developer does generally perform these early-stage activities of battery development. If the third-party developer intends to sell the asset, it may do so at varying stages of project development with a willing off-taker. In a build-own-transfer arrangement, the third-party developer also hires and oversees the EPC. If a sale is contemplated prior to asset construction, the third-party developer may perform some or all of the early-stage development activities.

For a self-developed Duke standalone storage project, the Companies would perform these early-stage activities of battery development.

Q. DO YOU AGREE WITH WITNESS DiFELICE THAT THIRD-PARTY DEVELOPERS CAN CREATE BUILD-OWN-TRANSFER PROJECTS MORE COST-EFFECTIVELY THAN DUKE ENERGY?[35]

A. No. There is no compelling evidence to suggest that a developer stepping in as an intermediary to create a build-own-transfer structure for batteries is more cost-effective than a utility self-developing the battery project.

Q. DOES DUKE ENERGY AGREE WITH WITNESS DiFELICE THAT ALLOWING THIRD-PARTY DEVELOPERS TO PARTICIPATE IN STAND-ALONE ENERGY STORAGE DEPLOYMENT WILL INCREASE THE SPEED AT WHICH THE RESOURCES COME ONLINE?[36]

A. No. Allowing third-party developers to participate in stand-alone storage will not increase the speed that batteries can come online because the storage facilities are still subject to the same interconnection cluster processes and timelines. Utilizing existing utility-owned land and siting utility self-developed batteries near existing or retiring utility generators, on the other hand, offers advantages in shortening the deployment timeline,

[35] CCEBA DiFelice Direct Testimony at 9.
[36] CCEBA DiFelice Direct Testimony at 9.

either from interconnection study or minimizing construction of interconnection facilities. This is in sharp contrast to the majority of solar generation projects because, in those cases, the developer already has site control that is not available to the Companies.

Q. ARE THERE ADVANTAGES TO THE COMPANIES SELF-DEVELOPING STANDALONE STORAGE PROJECTS RATHER THAN PROCURING THROUGH BUILD-OWN-TRANSFER AGREEMENTS?[37]

A. Yes. There are many advantages to the Companies developing and managing the construction of their standalone storage facilities. First and foremost, I want to emphasize that self-development does not mean the Companies will not leverage third-party expertise and utilize RFP practices to drive down prices—as stated above, we have a long track record of leveraging third-party expertise and RFPs across our entire business, including standalone storage. However, since the footprint for storage is not as dependent on geography as for renewable resources or even thermal generators, the Companies are seeking to site future battery projects based on existing grid assets, proximity to load centers, and available land at existing sites to reduce the complexity and cost of developing these batteries. This integrated planning approach is focused on leveraging existing assets to lower costs for customers, while also avoiding the cost to

[37] CCEBA DiFelice Direct Testimony at 9.

customers of adding an intermediary to perform the role of project managing the construction before selling the project to Duke Energy.

Incremental solar is very different, since it is needed to create additional carbon-free energy and typically requires that new land be utilized to produce the new energy. Additionally, self-developing battery storage projects facilitates implementation of these resources' evolving safety and design standards, which are not mandatory or consistent across the country. The Companies continue to enhance the community engagement and fire safety efforts around batteries, and would be hamstrung to change safety standards or requirements of a build own transfer project at any point after the contract was executed, even when new recommendations are established in the industry. For example, after the Arizona Public Service battery fire in 2019, DEP paused development efforts at the Hot Springs Microgrid project and the Asheville Rock Hill battery to learn more about the incident from industry peers and subject matter experts in order to incorporate new fire safety measures into the project design. The Company was able to take these reasonable actions because it was self-developing the project and was not contractually limited to the pre-specified safety measures.

By self-developing standalone storage assets, Duke Energy is able to closely oversee construction quality and safety as well as effectively negotiate warranties and performance guarantees based on a flexible future use.

Q. IS STANDALONE STORAGE APPROPRIATE FOR AN OPEN BUILD-OWN-TRANSFER PROCUREMENT PROCESS AT THIS TIME?[38]

A. The Companies support all available avenues to keep customer costs low, and would be open to further exploring options for a future build-own-transfer RFP for standalone storage. In such a scenario, the RFP would be subject to Duke Energy-directed siting based on system needs, benefits, timing, and other requirements. The technical requirements for a standalone storage acquisition RFP would be very specific, including approved vendors and equipment, design standards, safety requirements, capacity and energy content, and appropriate use case-driven capabilities. The Companies continue to believe that a BOT model may not be appropriate or feasible in all scenarios but the Companies would, in every case, utilize competitive sourcing processes for the benefit of customers.

VI. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

[38] CCEBA DiFelice Direct Testimony at 21.

Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Summary of Rebuttal Testimony – Transmission and Solar Procurement
Sammy Roberts and Maura Farver
Carolinas Carbon Plan
Docket No. E-100, Sub 179

Our rebuttal testimony provides further evidence for the Commission of the critical importance of the key near-term actions to immediately beginning the transmission system transformation actions necessary for successful execution of the Carbon Plan: (1) obtain FERC approval of generator replacement queue process; (2) subject to TAG review and NCTPC approval, start RZEP transmission projects; (3) start preliminary activities for offshore wind transmission projects with point of interconnection at New Bern Substation; (4) perform further Transmission Planning evaluations/studies for transmission transformation needed to facilitate coal generation retirements; and (5) request interconnection studies for needed MW levels of offshore wind being injected into New Bern Substation.

Since the filing of direct testimony, FERC approved the Companies' generator replacement proposal, which is a key initial accomplishment in the Companies' execution plan. The Companies are proceeding to implement the generator replacement process, which will be critical to efficient, timely, and cost-effective replacement of existing coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located.

The Companies agree with a number of parties on the need for proactive transmission planning to support the pace and volume of interconnecting resources necessary to implement the Carbon Plan. The RZEP projects are a key example of Duke Energy's commitment to proactive planning and a necessary and appropriate first step in this direction as they have multiple value propositions in addition to facilitating improvement in the pace and volume of interconnection of incremental resources. There is widespread agreement among many parties regarding the need for RZEP projects. The Companies seek Commission acknowledgement of the need for 14 RZEP projects based on the supplemental studies discussed in our direct testimony. The Public Staff is generally supportive of the supplemental studies and supports Commission acknowledgement of the majority of the projects. The Company agrees with the Public Staff that the Camden-Camden Dupont 115 kV line upgrade may be able to be postponed subject to continued scrutiny, but continues to support acknowledgement and continued pursuit of the Clinton 100 kV B/W lines and the Erwin-Fayetteville 115 kV line based on the results from prior generator interconnection studies and the supplemental studies, as well as potential cost and timing savings that can be realized by pursuing these projects at this time.

With regard to offshore wind, the Companies need to immediately start preliminary activities for offshore wind transmission projects with the point of interconnection at the New Bern Substation in order to meet an in-service date that facilitates bringing offshore wind energy into the DEP system by 2030. New Bern is the best potential point of interconnection based on cost and feasibility.

As to other matters raised by intervenor testimony, CPSA's assertions regarding the Companies' solar interconnection modeling assumptions are not informed by the specific considerations of the DEC and DEP systems and interconnection procedures, including for example the extension transmission line outages required to construct interconnection facilities and transmission network upgrades needed to interconnect resources.

Finally, based on the strong foundation laid through CPRE and now the 2022 Solar Procurement, and consistent with the Companies' recommended near-term procurements, the Companies plan to solicit solar and solar paired with storage resources in future procurements starting in 2023. It will be necessary to develop substantially new contract forms to facilitate the purchase of output from third party owned solar facilities paired with storage that meets HB 951 requirements, and the Companies plan to engage stakeholders with respect to such contract development in advance of the 2023 procurement. With regard to standalone storage, while the Companies are open to further exploring options for a future build-own-transfer competitive solicitation, the technical, safety, and location specifications for such an RFP would be very specific in order to account for the Companies' system needs, benefit, timing, and other considerations.

This concludes our summary of the panel's rebuttal testimony.

MS. KELLS: I'd also ask that the panel's three exhibits be marked for identification as prefiled.

CHAIR MITCHELL: Exhibits to the panel's testimony will identified for -- will be marked for identification as they were when they were prefiled.

MS. KELLS: Thank you.

(Whereupon, Transmission and Solar Procurement Panel Rebuttal Exhibits 1, 2, and 3 were identified as premarked.)

MS. KELLS: The panel is now available for questions from the parties and the Commission.

CHAIR MITCHELL: All right. Let's see. We've got CCEBA.

MR. BURNS: Thank you. For the court reporter my name is John Burns with -- representing CCEBA.

CROSS EXAMINATION BY MR. BURNS:

Q Good morning, Panel.

A (Roberts) Good morning.

A (Farver) Good morning.

Q I have just a very few questions for you. I notice that you filed, or Duke filed amended testimony that corrected -- well, in particular, the testimony on page 43 of your rebuttal testimony related to the build-

own-transfer procurement process; is that correct?
A (Farver) That's correct.
Q Ms. Farver, could you tell us what the essence of that -- of that change is.
A The earlier draft of the rebuttal testimony stated that we were not going to pursue a build-own-transfer option for standalone storage, and upon further reflection, we have edited that to allow for further discussion about the potential benefits of a build-own-transfer arrangement for standalone storage.
Q So it's -- the Company is now open to the discussion and possibility of build-own-transfer for standalone storage?
A Yes. We'd like to learn more about that.
Q Okay. I also have a quick question. If you'll turn with me to page 2 of your testimony, as revised -- I don't think the revisions affect this page, but you're discussing -- and I'm not -- Mr. Roberts, I think this is you. In response to the question "Mr. Roberts, what is the purpose of the Transmission and Solar Procurement Panel's rebuttal testimony," you list some things and then discuss Table 4-13 of Chapter 4 of the Execution Plan, correct?
A (Roberts) Correct.

Q Okay. I just have a quick question. You list five things, five actions there from that original table. The fourth is "Perform further transmission planning evaluations and studies for transmission transformation needed to facilitate coal generation retirements." And the fifth is "Requesting interconnection studies for needed MW levels of offshore wind." This -- for once, I have a question that's not a targeted cross examination question, and it's just a question of what is the difference, for all of our understanding, between the types of transmission planning evaluations and studies you mention in four, and the interconnection studies in five? What's the practical and the real difference between those types of studies?

A Yeah. So a retirement study is specifically that. You're looking at taking the existing generation away; if you don't replace it on site, what transmission upgrades will be needed, performing a more formal analysis associated with that retirement study, versus an interconnection study, you're saying I want to connect a certain level of MW at this point of interconnection, and you're studying that injection into the system through our formal LGIP process.

Q Okay. So the studies contemplated in paragraph four there are specifically related to the coal generation retirement, so there's not transformation planning evaluations and studies that might apply to a different type of problem that Duke is evaluating?

A So it's specifically meant to apply to retirement of generation and not replacing on site.

Q Would it be possible to do the, you know, transmission planning and evaluations of study -- and evaluation/studies for other issues that are before this Commission, such as the three wind lease areas?

A I'll let the Long Lead-Time --

Q Okay.

A -- Panel refer --

Q That's a fair response. Thank you.

A -- respond to that.

Q I appreciate that. And for the panel, both of -- your rebuttal testimony spends a good bit of time emphasizing the need for the RZEP projects, correct?

A That's correct.

Q And there's nothing that's changed between your original testimony and your rebuttal testimony that would have the Company backing off from its assertion that these Red Zone projects are essential for the implementation of the carbon plan?

A So we definitely believe the RZEP projects are essential for executing the carbon plan. After we filed our direct testimony and the supplemental studies as exhibits that indicated 15 of the original 18 projects showed up as being impacted through the supplemental studies, the Public Staff responded through their direct testimony and recommended an additional three projects to be delayed, monitored, and they offered that we could provide a different stance if we wanted to in our rebuttal testimony, in which I do. I respond that two of those three projects, based on certain parameters such as enabling a certain amount of solar, you know, the benefits that they provide are still needed.
Q Would you agree that the Red Zone -- the proposed Red Zone projects would be at least an early example of the type of proactive generation plus transmission planning that is needed as we go forward with the carbon plan?
A Yes. That’s indicated in my direct testimony and my rebuttal testimony, that it is an example of the proactive transmission multi-value network upgrades that are going to be needed to execute this carbon plan.
Q The current -- I also note that there’s some discussion in your rebuttal testimony about the proactive

transmission planning, which you just identified Red Zone as an example of that. But the process itself with the NCTPC, would the Company be -- are you in a position to speak for the Company as to whether the Company would be open to changes in that process to involve the comments and proposals of parties other than the transmission operators?

A So could you point me to the section you're referring to?

Q Well, you don't actually go into that, and I'm struggling to find your exact part. Let me look back at your -- bear with me one moment. I can make this more efficient. In the discussion after page 3, I believe, related to the Red Zone, you then go further to talk about -- well, pardon me. Just hold on and I'll be right there. Sometimes I lose my place. Well, strike that. I'll just ask a different question.

In terms -- with regard to the NCTPC process as it currently exists, is Duke open to changes in that process to more fully involve stakeholders in the decision making process in NCTCP as to the approval and disapproval of proposed transmission upgrades?

A Yeah. So, I mean, I think the avenue for stakeholder involvement is sufficient with respect to the

Transmission Advisory Group and being able to provide input on local projects identified through the NCTCP process and studies and suggest alternatives or suggest that it may miss the mark, and we have to -- I mean, per the FERC process, in Attachment N-1 in our OATT, we have to address that feedback. I mean, that's the whole purpose of the stakeholder process. I do think, since the entities that are responsible for -- ultimately responsible for paying for the transmission, you know, as far as FERC projects go, they should be the ones making the decisions, the ultimate decisions, but we're required to absorb that input from the TAG stakeholders and address that.

Q Isn't, though, the TAG process, by its very nature, currently reactive to proposals of projects that are identified as needing transmission upgrades as a result of the project?

A So no. I mean, I think any proposals -- you know, we can't accommodate 100 proposals in a year, but I think any proposals we could address through the NCTCP process through a study, and we've done that. I mean, the Public Staff has requested to analyze, you know, our future portfolio through the NCTPC process. I do think we need to change the manner in which we conduct the studies such that they're more aligned with our generator interconnection studies and, thus, the results are more in line with what we would see from the generator interconnection study once the interconnection customer makes that request and goes through the DISIS process.

Q I'm going to ask one of those questions that a lawyer shouldn't ask, which is one that I don't know the answer to, but how would you suggest, Mr. Roberts, that the generation planning be more involved with the transmission planning as part of the NCTCP process, because we've all talked about that as what we understand to mean by proactive. How do you logistically do that in the context of the current NCTCP process?

A Yeah. So there's multiple ways, but, you know, public policy request, and then we receive input from that developer or planner, and it states here's what we offer as input for locations and sizes and MW for a certain type of resource, and we can study that.

Q And would those -- and would it be possible to use the public policy process or the public policy request process if that request came from the Commission itself?

A So the Public Staff has issued a public policy request to the NCTPC, and we conducted the study. I think that would be a proper route. I think the OATT allows the Commission to have that avenue through TAG to submit a public policy request. That's subject to check.

Q Thank you.

MR. BURNS: No further questions at this time.

CHAIR MITCHELL: All right. Who's up next?

MS. CRESS: I believe CIGFUR, Chair Mitchell.

CHAIR MITCHELL: Okay.

CROSS EXAMINATION BY MS. CRESS:

Q I think I have just two questions for the panel. Good morning.

A (Roberts) Good morning.

Q You were in the hearing room this morning when your colleague, Ms. Bateman, testified about jurisdictional cost allocation issues; is that right?

A Yes.

Q Could classification of RZEP projects as public policy projects potentially create additional jurisdictional cost allocation problems?

A So I'm not an expert on jurisdictional cost allocations. I know, you know, FERC's stance is that network transmission is to the benefit of all network customers, so all the network customers in DEP would benefit from the network upgrades associated with the

RZEP projects. All the network customers in DEC would benefit from the RZEP projects in DEC. That is FERC's stance.

Q Thank you.

MS. CRESS: Nothing further.

CHAIR MITCHELL: All right. CPSA?

CROSS EXAMINATION BY MR. SNOWDEN:

Q Good morning, Ms. Farver, Mr. Roberts. Mr. Roberts, I'd first just like to follow up on CCEBA's last couple questions about transmission planning just very briefly. Would you agree that in an integrated transmission and resource planning process a series of portfolios are provided and then those portfolios get studied to identify what that would mean in terms of transmission upgrades?

A (Roberts) So that's a scenario-based approach.

Q Okay. Is that sort of -- is the scenario-based approach the way Duke would recommend we move forward with transmission planning?

A I think as mentioned by other Intervenors, it has to be a holistic approach, and you basically have the expansion plan, and through input from this Commission, we now incorporate network upgrade cost proxies into that decision making associated with the selection of those resources. And so, I mean, that is baking in the transmission. Then once you have that network cost proxy, you need to make sure that that proxy, you know, reflects what actual upgrades are. That's why we go back to generator interconnection studies if we have them to develop those cost proxies. Looking forward out, from I'm hearing from Intervenors and what I agree with is that a proactive transmission planning approach looks at that transmission needed to facilitate that resource plan holistically, and you maximize the overall benefits, looking at the cost holistically.

Q Thank you for that. So I just want to understand. As Duke foresees it in the TPC process, that the TPC itself will study a resource plan or portfolios; is that right?

A The TPC process, yes, can study a portfolio.

Q Okay. And how does the TPC know what portfolios to study -- or let me ask it another way. Where do those portfolios come from?

A Right. So usually in the past we've looked at an approved IRP, and based on that approved IRP, things like dates for generator retirements, that goes into the models that are studied associated with that portfolio.

Q Understood that that's how it's been done in the past. I guess what I'm asking is how you foresee the resource planning process or the carbon planning process feeding into the TPC going forward?

A Right. So we may have to -- based on what this Commission approves as a carbon plan, if it's near-term actions, we make sure those near-term actions are represented in the models. If it's a certain portfolio or maybe it allows for a range of portfolios, three or four portfolios, then we could look at those three or four portfolios.

Q Okay. All right. Thank you. Ms. Farver, I'd like to ask you some questions about the Red Zone upgrades. So you testify that the Red Zone upgrades will allow for more interconnection of solar facilities in the Red Zone, right?

A (Farver) That's correct.

Q Okay. And you say -- and I'm looking at page 6, starting with line 11 of your rebuttal testimony. Actually, I guess this is on line 15. You say that "To date these Red Zone upgrades have created insurmountable cost hurdles for developers of one or two projects being asked to bear the up-front burden of that cost." Is that right?

A That's correct.

Q And I would paraphrase your testimony as saying that the RZEP will create benefits for a large number of projects, but if the cost is allocated to a small number of projects, it makes their economics untenable. Is that a fair characterization?

A Historically, yes. Those costs have made those projects in the past untenable.

Q But Duke believes that the RZEP are an efficient investment if the whole amount of generation that will be facilitated by those upgrades is considered; is that right?

A That’s correct.

Q And based on the supplemental study that Duke has performed, that additional generation is somewhere north of 3600 MW; is that right?

A Correct. And Mr. Roberts can weigh in on the supplemental study.

Q All right.

A (Roberts) Yes. So the supplemental studies did show that, subject to check, around 3600 -- a little over 3600 MW would be enabled by the Red Zone projects. It also identified that there could be other upgrades. There could be upgrades locating outside the Red Zone. There could be other upgrades locating inside the Red

Zone.
Q Understood. Thank you. Ms. Farver, I'd like to ask you a couple questions about the current DISIS process in the RFP, if I may. You testify in your direct testimony -- we can go there, but I do want to establish, you say in your direct testimony that there are approximately 5000 MW of solar in the current RFP, about 70 percent of which is in the Red Zone; is that right?
A (Farver) That's right. We corrected that to approximately 4900 MW, but it's still approximately 70 percent of the MW.
Q Thank you. So that's about 3500 MW, give or take?
A Roughly.
Q Okay. And that's approximately the number of MW that the supplemental studies say would be facilitated by the Red Zone upgrades, right?
A Correct.
Q So moving to DISIS, DISIS is a two-phase interconnection study, isn't it?
A Yes. It is designed to be Phase 1 and Phase 2. There is a provision that if a Phase 3 is necessary, it could continue.
Q And in Phase 1, Duke conducts a power flow

study of all the projects that go into DISIS, right?
A That's right.
Q And that study identifies the upgrades that are required to interconnect all those projects, doesn't it?
A Correct.
Q And it allocates the cost of those upgrades across all of the projects that participated in Phase 1, according to their impact.
A Yes. That's more or less true.
Q Okay. So going back to the number of MW that are in DISIS and the number of MW that are considered in the supplemental study, would you agree that in the Phase 1 study of the current DISIS process, the cost of the Red Zone upgrades will be spread among roughly the same volume of projects that will ultimately be facilitated by those upgrades?
A I think that's more or less accurate. Of course, the projects that are in this current DISIS are different, or potentially some of them at least are different from what was studied in the supplemental study, and so we don't know which of these projects are contributing to which of the specific Red Zone upgrades, but from a sort of high level standpoint, yes, they will be allocated, the cost across the projects that are

there. And furthermore, there might be projects outside of the RFP that are in DISIS that are also picking up a portion of that cost if they're in the Red Zone.

Q Thank you. So would you agree that the allocation of cost to Red Zone projects in DISIS Phase 1 provides a very rough, but probably conservative approximation of the cost those projects would be allocated if you spread them across all the projects that would benefit from the Red Zone upgrades?

A It is one way to create an approximation, but because -- you know, when we say Red Zone, we often just lump them all together, but there are distinct projects within that, and every solar project is going to have a different DFAX or contribution to each of those specific upgrades. So it would be one mechanism to draw a very rough approximation, I think.

Q Thank you. Moving on to the Phase 2 study, you'd agree that you'd likely have fewer projects in DISIS Phase 2 than were in Phase 1, right?

A Well, the number can only go down since no projects can be added, and projects will make a decision about whether they choose to move forward into Phase 2. That's right.

Q And most, if not all, of the projects that are

not selected in the RFP will likely drop out prior to Phase 2; is that right?
A I can't speculate on what those projects choose to do, so I don't -- I don't think I can specifically answer that.
Q Okay. Well, how about this? Unless a project that is not selected, you know, in the RFP has another way of establishing offtake and thereby meeting the readiness requirements for Phase 2, they'd be likely to drop out before going into Phase 2, wouldn't they?
A They would have to establish a different form of readiness in order to continue in the DISIS process.
Q Okay. And so would you agree that the Phase 2 study will identify upgrades and allocate cost based on a smaller set of projects than the Phase 1 study?
A It will be, sure, either the same number or a smaller number of projects than in Phase 1. That's right.
Q And if the Red Zone upgrades are triggered in Phase 2, the cost would be allocated to a smaller set of projects, wouldn't they?
A Whichever projects are remaining, that's correct.
Q Understood. And commensurately, fewer projects

would ultimate--- well, if it's a smaller number of projects, then the cost will be allocated to fewer projects than will ultimately benefit from the Red Zone upgrades, won't it?

A That is -- can you repeat that?

Q Sure. If a number of projects drop out after Phase 1 before going into Phase 2 and the Red Zone upgrades are triggered, then the full cost of those Red Zone upgrades will be allocated to a smaller set of projects, right?

A Sort of, because we don't know if all of those upgrades identified in Phase 1 will still be necessary in Phase 2, so as there are fewer projects, perhaps there are fewer upgrades needed. But to the extent that the upgrades are still needed in Phase 2, then that cost would be allocated over a smaller number of projects, and there can and likely will be future projects that would also benefit from those upgrades.

Q Okay. Thank you. And here's where I'm going. Did you happen to hear Commissioner questions yesterday and the Modeling Panel during which Chair Mitchell expressed concerns about whether we were sending appropriate price signals to solar projects with regard to locating in the Red Zones?

A I caught some of that discussion. I’m not sure if I caught it all.

Q Okay. Would you agree that if no cost for Red Zone upgrades were allocated to solar projects, that might send an inappropriate price signal to developers in the near term?

A Can you explain what you mean by “inappropriate price signal”?

Q That’s a great question. And I am going to take a risk here and try to paraphrase the Chair, but I believe that she expressed a concern that if the Red Zone upgrades got incorporated in the local transmission plan and there were no costs allocated to projects locating in the Red Zone, that would send an inappropriate price signal for projects to develop into the Red Zone because they wouldn’t be bearing any cost for those upgrades.

A I do think the cost of the Red Zone upgrades needs to be considered when you’re looking at the portfolio that you’re selecting, but how those costs are allocated, whether it’s falling to the generators individually through the DISIS process or through the Red Zone process, I’m not sure that that makes a difference. So in the evaluation I think you should consider what the associated transmission impacts are regardless of how those transmission costs are borne, I suppose.

Q Thank you. Well, let me ask you another question. Would you agree that for purposes of bid evaluation, it would be inappropriate or it would send an inappropriate price signal to fully allocate the entire cost of the Red Zone upgrades to a smaller set of projects than will ultimately benefit from them?

A So this is one of the challenges with, I suppose, proactive transmission planning, that we have assumptions and we're using information that we have available to us about the scope of projects that we believe will be utilizing or can utilize these upgrades, but our view into the future isn't perfect, so understanding what that full denominator is of the full number of future MW that will benefit from these upgrades is impossible to specifically define right now. We know that there will be future MW and we can look at specific scenarios, but it is unclear just how many MW we should spread that cost over to come up with sort of an LCOT. Did you want to --

A (Roberts) Yeah. That's absolutely correct and, I mean, it's going to depend on location and size as well. I mean, one of the things we're pretty confident of is that the Red Zone expansion plan projects will enable larger solar facilities to be interconnected, and so that's -- that would allow more MW for a given number of interconnections --

Q Okay. Thank you.

A -- as one of the benefits.

Q Thank you. So given that there's all this uncertainty and it's probably difficult to create a perfect price signal for projects to develop or not develop in the Red Zone, would you agree that the Phase 1 cost allocations for the Red Zone upgrades might be an appropriate sort of proxy price signal for use in bid evaluations?

A (Farver) I would want to check with the team who's actually performing those evaluations. I think that taking that full number and spreading it across all of the MW in the Red Zone would be a very rough way to do it since we don't know on a project-by-project basis which project is contributing to what at this point in time. It is one way to come up with a very rough approximation of how to spread those costs.

Q Thank you. Understanding it would be very rough and for all the reasons we've discussed, do you think it would be appropriate to consider that as a way of sending an appropriate price signal in the bid evaluation process?

A I think for future solar procurements we should have further discussion about how best to account for transmission costs assigned to projects -- I should say transmission costs assigned to projects for evaluation purposes if those transmission costs are not being borne by the generator in the DISIS interconnection process. So for a Red Zone upgrade, how are we making sure that we're not assigning a zero transmission cost to a project that's benefiting from Red Zone upgrades that were approved through a different mechanism, but also not assigning one project the full cost of all of the Red Zone upgrades because that also is not an accurate reflection of the -- I suppose the project's cost.

Q Thank you, Ms. Farver. Moving on, Mr. Roberts, on page 27, starting on line 8 of your rebuttal testimony --

A Okay.

Q -- on page 27, line 8 of your rebuttal testimony you provide your respo--- you begin to provide your response to witness Watts' assertion that Duke should encourage third-party self build of interconnection facilities and standalone network upgrades; is that right?

A (Roberts) That’s correct.
Q And in your response on page 27, you first briefly discuss Duke’s interconnection standards for transmission interconnected projects, correct?
A That’s correct. And that was part of the redline correction that was made.
Q All right. Thank you. I’m sorry. Can you tell me again what the correction was for clarification?
A Yes. So just to paraphrase, on line 18, it says must -- if connected to a network 230 kV transmission line, must have a ring bus station installed at point of interconnection for protection and isolation purposes. And so with our criteria -- you go through a criteria, so it’s not an absolute that a ring bus is required. It’s recommended, but it’s not an absolute that it’s required.
Q Understood. Thank you. Moving on to page 28, excuse me, on lines 1 through 5 you talk about the need for line outages; is that right?
A That’s correct.
Q And then the next thing you say is that “Because of this impact to day-to-day transmission operations, reliance on third-party construction introduces significant reliability risk. In fact, the

DEC and DEP OATT and the modifications required by FERC Order No. 845 acknowledge this distinction, providing the option for interconnection customers to build interconnection facilities and standalone network upgrades, not network upgrades that risk adverse reliability impacts." Did I read that correctly?

A That's correct, but I'd like to put that in context. And what that's stating is that we basically need to be in control of reliability, right? I mean, where NERC has us championing reliability, meeting the NERC reliability standards, we have to be in compliance with those 24/7, 365. And so what this is saying is that we don't want to create an outage such that a solar developer or any interconnection customer is working on interconnection facilities and putting that transmission system at risk, energized transmission system at risk. The OATT does allow for, and I think Mr. Watts mentioned shoe flies, or a temporary line as you defined it, and so the OATT does allow for standalone network upgrades, i.e., upgrades being built that do not put the network transmission system in jeopardy or a reliability risk. That's what this is stating, this section is stating.

Q Okay. So I take it from your testimony that you agree that interconnection customer construction of standalone network upgrades does not put the system at reliability risk?

A Right. I mean, we would -- we would have to assess that, but, yes, that’s what it’s saying. And Order 845 from FERC required us to put that option into our open access transmission tariff.

Q Uh-huh.

A Every transmission provider has to have that option.

Q Thank you. So as you say, FERC has concluded that allowing interconnection customers to self build interconnection facilities and standalone network upgrades does not risk adverse reliability impacts; is that correct?

A I don’t know if that’s FERC’s explicit conclusion. I just know that they require the transmission service provider to allow for the provision of self build options with standalone network upgrades, and that’s what’s in our tariff.

Q Okay. Well, you say here that under the OATT, customers can self build standalone network upgrades and also interconnection facilities?

A Yes. That’s correct.

Q All right. So Duke’s OATT allows FERC

jurisdictional customers to self build interconnection facilities and standalone network upgrades, correct?

A That's correct.

Q Okay. Could you turn back to page 27, please, and read lines 8 through 11?

A "What is your response to witness Watts' assertion that Duke should encourage third-party self build of interconnection facilities and standalone network upgrades?"

Q Thank you. So as you explain it, witness Watts' suggestion is only that Duke should encourage third-party self build of interconnection facilities and standalone network upgrades, correct?

A I believe witness Watts was referring to -- well, I believe he generically referred to network upgrades, and so this specifically isolates that to standalone network upgrades, i.e., network upgrades that won't waste the network transmission system at a reliability risk.

Q Okay. Well, as you explain witness Watts' recommendation in your testimony, you say that he's only recommending self build for interconnection facilities and standalone upgrades, correct?

A That's what I have stated in the question.

Q Okay. And that's already allowed for Duke's FERC jurisdictional customers, correct?
A FERC Order 845 requires it, yes.
Q Okay. And if that were permitted for state jurisdictional interconnection customers, that would only allow those customers to do what FERC jurisdictional customers of Duke can already do, correct?
A That's correct.
Q Okay. Thank you. Ms. Farver, would you agree that because of economies of scale, larger solar projects are generally -- not always, but generally likely to have better economics than smaller projects?
A (Farver) That can be one contributing factor.
Q Okay. Thank you. Mr. Roberts, I'd like to turn to page 25 of your testimony, if I may.
A (Roberts) Okay.
Q Okay. And on page 25 you say that -- make sure I have the right line number here -- sorry. On page 25, line 4, you say that "the Companies believe that 14 to 15 interconnections can likely be achieved in the near term." Do you see that?
A Yes. And it further says "From a transmission perspective this is a reasonable but aggressive target."
Q Okay. So when you say 14 to 15, you mean

transmission interconnections?

A That's correct.

Q Okay. And in the near term?

A Once again, it's based on outages, it's based on having to coordinate all the outages. I looked back at 2021. We coordinated close to 1100 outages, most in the spring and fall. So we have maintenance outages, we have NERC PM outages, we have outages for TPL 001 reliability projects, we have outages to connect new points of delivery for retail, new points of delivery for wholesale. There are a lot of outages to coordinate in order to ensure we maintain reliable electric service throughout each year.

Q Okay. Well, thank you, Mr. Roberts. I didn't ask you about outages; I just asked you to confirm that, as you said here, that this is a near-term estimate.

A I'm providing the reasoning for the 14 to 15 interconnections, and that 14 to 15, if you look at Figure 15 in the modeling testimony, direct testimony, it shows that the Red Zone projects are needed to enable getting to 14 to 15 interconnections per year annually.

Q Okay. Thank you. So that 14 to 15 interconnections per year, I mean, that's a current assessment, right?

A That's correct.

Q Okay. Thank you.

MR. SNOWDEN: Chair Mitchell, I would like to have marked for identification an exhibit. This would be Transmission Panel Rebuttal -- I'm sorry -- CPSA Transmission Panel Rebuttal Cross Exhibit 1.

CHAIR MITCHELL: All right. The document will be marked for identification purposes as CPSA Transmission Panel Rebuttal Cross Examination Exhibit 1.

MR. SNOWDEN: Thank you.

(Whereupon, CPSA Transmission and Solar Panel Rebuttal Cross Exhibit 1 was marked for identification.)

Q Mr. Roberts, this exhibit shows the solar projects that are in DEC and DEP's combined interconnection queues as of July 10, 2022. Do you see that?

A Yes.

Q Okay. And I'll represent to you that all the information -- all the information on this exhibit comes from DEP's and DEC's OASIS websites, and I'll further represent to you that it was pulled from those websites in the last 48 hours. So as far as I know, this is the most up-to-date information available. So this exhibit shows the combined DEC and DEP queues in the DISIS study. Would you agree with that?

A Yes.

Q Okay. And you see that there are both state jurisdictional and FERC jurisdictional projects on this table?

A I do.

Q Okay. And would you agree that under HB 951, 55 percent of solar resources that are added will be owned by the Company and 45 percent of solar resources will be third-party PPAs?

A That's correct.

Q Okay. And would you agree that in a DISIS process, PPA proposals go in the state jurisdictional queue and utility ownership proposals go in the FERC queue?

A (Farver) I can answer that. For our RFP for those proposals that were bidding both state -- excuse me -- both PPA and utility ownership track, they were instructed to have a state jurisdictional interconnection agreement, and then if they were selected for utility ownership track, they will change to FERC jurisdictional later.

Q Okay. Thank you for that clarification. And state jurisdictional projects are not allowed to be any larger than -- well, sorry. Strike that. PPA projects bidding in to the RFP are not allowed to be any larger than 80 MW; is that right?

A That's correct.

Q Okay. And let's see here. Utility ownership proposals, however, are -- do not have any size cap, right?

A That's correct, in the '22 solar procurement.

Q Okay. And similarly, FERC jurisdictional -- I'm sorry. FERC jurisdictional projects have no size cap and state jurisdictional projects have an 80-MW cap; is that right?

A I don't actually know if state jurisdiction has a cap, but in order to qualify as a QF, it would be 80 MW.

Q Okay. You're not aware of there being any state jurisdictional interconnection customers that are larger than 80 MW, are you?

A From looking at this report, no.

Q Okay. Thank you. I'd like to direct your attention to page 3 of the exhibit, please. And do you see where it says Average Project Size?

A Yes.

Q Okay. And I will represent to you that these are just calculations based solely on the information that is shown on this table. Subject to check, would you agree that this shows that the -- indicates that the average size of a FERC project in Duke's DISIS queue is 137.5 MW?

A Subject to check.

Q Okay. And subject to check, the average size of a state jurisdictional project is 68.3 MW?

A Subject to check.

Q And subject to check, that the overall average size is 84 MW?

A Subject to check.

Q And here's what I'm getting at here. We've had a lot of back and forth I know with Mr. Watts and Mr. Roberts about sort of qualitative reasons why or why not higher interconnection numbers might be achievable. I want to look at some numbers here and see what kind of interconnection rates might be achievable based on Mr. Roberts' estimate that Duke could reasonably achieve up to 15 interconnections per year. So with that, I'll tell you where I'm going, so -- all right. And I'll say this was made a little bit more complicated by this 55/45 percent split. The math was not easy.

Mr. Roberts, will you look at the -- do you see where it says Potential HB 951 Compliant Portfolios Based on DISIS 1 Project Size?

A (Roberts) Yes.

Q Okay. And I'll just represent to you that when I say -- when this says HB 951 Compliant, that means there is a 55 percent, or approximately a 55 percent/45 percent ownership split required by HB 951. So if you look at -- you see the first of these tables it says Average Project Size Overall?

A Yes.

Q Okay. And would you agree in this table that what this indicates is that with seven PPA projects and eight utility-owned projects all at the average size of 84 MW, that's a total of 15 projects?

A Yes.

Q Okay. And would you agree that the total MW of those 15 projects at that average size is 1260?

A Yes.

Q Okay. And turning to the next box here, do you see where it says Average Project Size by Category?

A Yes.

Q Okay. And do you see where it says PPA projects, nine at 68 MW, which is the average size of PPA projects?

A Yes.

Q Okay. And you see it says 614.8 MW?

A Yes.

Q Okay. And do you see where it says UOT, or Utility Ownership Projects, six at the average size of FERC projects of 137 MW? Do you see that?

A Yes.

Q Okay. And you see where it says 825.3 MW?

A Yes.

Q Okay. So would you agree that with this hypothetical portfolio, you would end up with 15 projects with a total combined capacity of 1440 MW?

A Yes.

Q Okay. And just moving on to the last box that says Largest Project Size by Category, do you see that?

A Yes.

Q Okay. And do you see where it says PPA Projects Top 10?

A Yes.

Q Okay. And I’ll represent to you that is just the largest 10 of the PPA projects on the list, and do you see where it says 800 MW?

A Yes.

Q So that would be 10 projects at 80-MW apiece. Would you agree with that math?

A Yes.

Q Okay. And then you see UOT Projects Top 5, 1038.3 MW?

A Yes.

Q Okay. And I'll represent to you that that is just the largest five of the utility ownership projects in DISIS 1. And what are the total MW of those projects on that table?

A Yeah. The top five?

Q Uh-huh.

A 1038.3.

Q Okay. So understanding that these are all hypothetical portfolios, would you agree that they all comply nearly with the HB 951 ownership split? And I'll represent to you that it's impossible to do it exactly with these project sizes.

A The 45 percent PPA --

Q Yes.

A -- 55 percent Duke ownership?

Q Yes, uh-huh.

A It's in the ballpark.

Q Okay. But would you agree that with the range of projects going from the average size all the way up to the largest project size, 15 projects could represent a portfolio of somewhere in the range of 1260 to 1838 MW?

A Yes. And, I mean, something in the middle is very close to our 1350 starting 2028 with respect to implementing the Red Zone projects.

Q Okay. Thank you.

MR. SNOWDEN: Those are all the question I have.

CHAIR MITCHELL: Okay. SACE?

MR. JIMENEZ: Good afternoon. Nick Jimenez with the Southern Environmental Law Center for SACE, et al. A couple questions for Ms. Farver.

CROSS EXAMINATION BY MR. JIMENEZ:

Q Ms. Farver, you testified that “there is now a strong foundation of established practices and structure (e.g. evaluation practices, bid documents, contract forms) on which to build in the future” for solar procurements, right?

A (Farver) Can you point me to a page so I have it for reference?

Q Certainly. Thirty-four (34), lines 18 to 20.

A Yes. I’m there.

Q And this has come through CPRE and now the 2022 solar procurement? Same reference?

A That's correct.

Q And you're responsible for designing and implementing the 2022 solar procurement, right?

A Yes. I coordinated the '22 procurement.

Q Thank you. Now, CPRE was overseen by an independent administrator, right?

A That's right.

Q And that was required by statute?

A That's right.

Q And the 2022 solar procurement is overseen by an independent evaluator.

A That's correct.

Q Are you familiar with Duke's petition to procure unawarded CPRE capacity through the 2022 procurement filed on September 1st, 2022?

A Yes. I am familiar with it.

Q Thank you. I have a few questions about that. I'll represent to you they're drawn from that petition. If you'd like to answer subject to check, that's fine with me, or you can answer whether you agree with the statement. That would also be fine.

Part of Duke's justification for switching from an IA to an IE was that Duke announced that no Duke

Energy affiliates will be participating in the 2022 SP, correct?

A That is one of the factors.

Q And Duke's nonparticipation eliminated some of the risks identified in the Commission's original rulemaking order justifying the need for additional, more robust oversight prescribed by Rule R8-71 for the 2022 SP, correct?

A Subject to check.

Q And those risks included Duke or its affiliates getting on the inside track by interacting with the IA, correct?

A Subject to check.

Q Under the 2022 SP, solar procurement, the Duke evaluation team does have a more significant role in bid evaluation and is responsible for selection of winning proposals, correct?

A That is correct.

Q For future procurements, if Duke or its affiliates participate, then Duke should use an IA again, should it not?

A I think that we have not designed those future procurements yet, and so it is too soon to know exactly the structure of those procurements or if affiliates would participate, but we are committed to having independent oversight, and I foresee using an independent evaluator in situations where Duke may also be bidding into the procurement.

Q Thank you.

MR. JIMENEZ: That's all the questions I have.

CHAIR MITCHELL: All right. Tech Customers?

MR. SCHAUER: We waive cross.

CHAIR MITCHELL: Public Staff.

MR. JOSEY: Thank you.

CROSS EXAMINATION BY MR. JOSEY:

Q Good morning, Mr. Roberts, Ms. Farver. I'm Robert Josey with the Public Staff. I just have a couple lines of, I think, mostly clarifying questions.

Mr. Roberts, on page 31 you discuss onshore wind imports. Were you listening to the hearing on Monday when I believe that it's Mr. Fitch who was representing several -- was a witness for several different parties here stated or discussed importing 2.5 GW of onshore wind from the Midwest?

A (Roberts) Yeah. I believe I caught that part of his testimony.

Q Okay. And he stated that he believed that the cost of the upgrades that would be necessary to import wind were embedded in the wheeling charges that would be charged for transmitting that onshore wind from the Midwest to North Carolina. Do you recall that?

A So, I mean, it depends on the origin of the Midwest wind and it depends on what provisions the transmission provider has in their tariff for establishing the rate.

Q Okay. So is it your understanding that wheeling charges in PJM and MISO include those upgrades that may be required to import 2 point GW of wind, onshore wind, from PJM or MISO into North Carolina?

A Right. If they discharge their standard point-to-point rate and didn't design a special rate based on certain network upgrades required, then it would be the point-to-point rate, which is -- we've referred to PJM as a border rate.

Q Okay. And so would the -- would the construction of the upgrades that would be required to enable a party such as Duke to import power into the state be an additional separate cost from the point-to-point transmission cost?

A So here's the total cost for wheeling power from, say, MISO all the way into the Carolinas. And this is just an example. Once again, there could be a special transmission rate, but it could be the -- it would be the point-to-point rate from MISO, the point-to-point rate on PJM, and then we would also have network transmission upgrades that would probably be necessary on the Duke system. And then you have the cost of the resource.

Q Okay. And could Duke's current transmission system import 2.5 GW of onshore wind from PJM or MISO?

A Not the current system, no.

Q Okay. Do you have any idea what the cost of those upgrades would be?

A So we looked at -- excuse me -- we looked at importing 1.5 GW and did that analysis, and that's what we're submitting the -- or have submitted, the transmission service request to PJM to validate that. We requested a TSR for 1000 MW. But based on that, the magnitude was over $700 million, and the time frame was really the critical factor. It was 84 months associated with construction of those upgrades just on the PJM system.

Q Okay. So for 1 GW you believe it's going to be somewhere in the neighborhood of $700 million in upgrades to the transmission system?

A So our study was for 1.5 GW.

Q Okay. So you would assume it would be quite a bit more for 2.5 GW?

A Yeah. It would probably definitely escalate.

Q Okay. Thank you. And then I just want to go back to a discussion you and I had on your direct testimony over the projects included in your Rebuttal Exhibit 3. And of the original 18 projects designated as RZEP projects, Duke decided to remove four, correct?

A That’s correct.

Q And the Public Staff has -- Public Staff witness Metz recommended that three of the initial 18 projects be removed from this RZEP; is that correct?

A So the -- I’ll just backtrack a little bit to get to witness Metz’s recommendation. So the supplemental studies identified 15 out of the original 18 projects. It did not include the Erwin-Milburnie 230, the Sutton-Wallace 230, or the Rockingham-West End West 230 lines. They didn’t show up in supplemental study. And then witness Metz reviewed the supplemental study results, and he recommended that the Clinton 100 lines, the Erwin-Fayetteville 115 lines, which was one of the original Friesian upgrades, and the Camden-Camden Dupont 115 should be delayed, also. And our response was we respectfully disagree. There’s quite a bit of solar behind the Erwin-Fayetteville 115 that it would enable, there’s quite a bit of solar behind the Clinton 100 lines that that upgrade would enable, but we agreed that the Camden-Camden Dupont could be delayed, but only because it's kind of a shorter duration project. For example, the Erwin-Fayetteville was identified in the transitional cluster study as taking 54 months to complete that upgrade. The Clinton lines were identified in the DEC transitional cluster study as taking 48 months to complete. So once again, if you have a lot of solar that wants to interconnect and it’s behind those upgrades, you’ve got quite a delay, and that’s what we’re trying to alleviate with respect to getting these Red Zone expansion plan projects proactively in place.

Q   Okay. And just to clarify, you say you have a lot of solar behind those lines, particularly the Clinton 100 kV, but in the supplemental study it only showed four study hits on that line; is that correct?

A   Well, there were -- there was actually -- based on my assessment of the results, there was actually 740 MW of solar facilities that met the DFAX threshold and/or the line loading impact threshold. And so if a solar facility met one or both of those thresholds, then that facility would be identified as a network upgrade need for interconnecting that source.

Q Okay. Thanks for that clarification. Ms. Farver, my next line of questioning is for you. Is it your understanding that the Commission issued an Order Approving Request for Proposals and Pro Forma Power Purchase Agreements Subject to Amendments on the 2022 procurement on June 10th, 2022?

A (Farver) Subject to check the date, but yes.

Q Yeah. Subject to check. And also subject to check, the Commission stated on page 9 of its Order, Ordering Paragraph 4, that Duke is directed not to include the RZEP projects in the 2022 DISIS baseline; is that correct?

A Yes, subject to check.

Q And is it your understanding of that Ordering paragraph that the RZEP projects should not be considered in the evaluation of bids in the 2022 RFP?

A They should be considered in the evaluation of bids, but not in the DISIS baseline, was my understanding.

Q Okay. All right. Yes. Thanks for that clarification.

MR. JOSEY: No further questions.

CHAIR MITCHELL: All right. Redirect?

REDIRECT EXAMINATION BY MS. KELLS:

Q Mr. Roberts, do you have Figure 15 from the Modeling Panel's direct testimony with you? If you don't, that's okay.

MS. KELLS: May I approach?

CHAIR MITCHELL: Yes. Do you know what page that's on, Mr. Roberts?

THE WITNESS: It's page 160, Figure 15.

CHAIR MITCHELL: Okay.

Q And do you have with you the CPSA Cross Exhibit 1 that you went over with Mr. Snowden?

A (Roberts) Yes.

Q Can you explain -- you see the first couple -- that Figure 15 shows the interconnections over the course of several years, correct?

A That's correct, starting with 2026, which would reflect the 2022 procurement.

Q And what are the interconnection levels there for the first couple columns?

A Eight.

Q Okay. Can you explain to us whether that figure is consistent with the data in the exhibit that you discussed with Mr. Snowden?

A Yeah. So as discussed with Mr. Snowden, he's got 15 interconnections, and we actually don't show 15 interconnections until 2030. We show 14 in '28 and '29. And so it's not entirely consistent with -- and we do show the Red Zone expansion plan projects as enabling those increased interconnections.

Q All right. Thank you. And just real quick on the questions about the third-party build that you went over with Mr. -- I'm sorry, I turned my microphone off -- so questions about third-party construction of interconnection facilities.

A Yes.

Q Is it your testimony that there's not really a dispute between your testimony and Mr. Watts' in this matter, but just that, you know, those can't be allowed when there are reliability -- negative reliability impacts to the system?

A That's correct. That's the main issue, is they were a reliability risk.

Q Thank you.

MS. KELLS: No further questions.

CHAIR MITCHELL: Okay. Questions from Commissioners? I will check in with Commissioner Brown-Bland. Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q Mr. Roberts, the retirement date for Marshall

Units 1 and 2, the earliest is the end of 2028. And I believe that Appendix P indicates that in order to achieve that date for retirement, you need to address a reliability issue on the McGuire to Marshall 230 kV line.
A (Roberts) So --
Q That’s my memory, right? Am I correct?
A You’re about 98 percent correct.
Q All right.
A The other 2 percent --
Q Give me the 2 percent.
A The other 2 percent is that if you replace the generation on site with equal capability --
Q Right.
A -- then you will still have must-run condition, that you can utilize that generation as the same capability to fulfill that generation.
Q If you replace it on site.
A That’s right.
Q And I don’t -- well, we can take the questions in whatever sequences work for you. I don’t recall seeing anywhere in the near-term action plan the identification of a generation resource to be located at the current Marshall Steam Station site. My recollection is correct, isn’t it?

A In the near-term action plan --
Q Right.
A -- I believe that's correct.
Q Yeah. So if that upgrade to the 230 kV line needs to be constructed, how long will it take?
A Yeah. So we do have a project with a specific project number in our transmission additions plan for DEC, and the date at which that's projected to be in service I believe is out at the 2030 time frame.
Q Your current project planning identifies that transmission upgrade as being available in 2030?
A That's correct, but that could accelerate. They're looking at different options with respect to building a temporary line and building it, basically rebuilding what's in place or using an alternate route or another line.
Q Say more about a temporary line. What is that? It's not the shoe flies that there's been some discussion about, is it? That's not what you're talking about, is it?
A No. A shoe fly is more of a short --
Q Right.
A -- temporary line.
Q So what is this kind of temporary line?

A It's a longer temporary line, and it would be built in parallel with the existing line such that you could take a length of section out of the existing line, upgrade it, rebuild it, and then move on down the line.
Q Built in the existing right-of-way.
A That's correct.
Q Okay. When I look at the list of projects on Table P-2, the project you just described is not on that list, is it?
A It --
Q Under some different name?
A That's correct.
Q Okay.
A Subject to check. Let me check.
Q Take a look at P-2. I was not able to identify it from the names of the projects on P-2, and if it has a different name in that exhibit, you can tell me.
A Yeah. That's correct. It's not in the P-2 list.
Q But it is an identified project that's not yet approved.
A So it's in the transmission additions plan. It's in the Copperleaf Capital evaluation tool as well. Whether it's gone to the next gate, project gate, I'm not

aware.

Q What would be the next gate?

A It would be the study phase.

Q And if -- I understand that project right now projects 2030. If you wanted to accelerate that again, getting back to my original question, to have that project completed in time for retirement of Marshall 1 and 2 by the end of 2028, when would the approval need to occur and when would you need to start construction?

A Right. So I don't know the specifics, all the specifics around that project, other than they're looking at options with respect to the temporary line in a different route where we already have right-of-way, so I don't know the -- when they would need to start in order to make a 2028 date.

Q Do you know how long the construction would take if you had to build a new line in the existing right-of-way?

A Just speculating, it would take quite a bit of time, but I don't know the project duration. I would have to ask the project manager what the duration is.

Q Well, what I'm really struggling for is are we out of time already in order to get the 2028 retirement of Marshall 1 and 2?

A Yeah. No, I wouldn't say we're out of time already. I mean, there's ways we can accelerate with, you know, multiple crews, et cetera, to speed up the construction.

Q But I take it you wouldn't try to invoke any of those accelerating steps until you first decide on whether you're going to put replacement generation --

A That's correct.

Q -- on Marshall 1 and 2. When will that decision be made?

A I don't know.

Q Could battery storage located at Marshall 1 and 2 and connected at the same interconnection point serve the reliability need that otherwise occasions this upgrade?

A So two issues with battery storage. One is the charging would exacerbate the condition --

Q Sure.

A -- right? So that would be like adding load at Marshall as they were charging, so you'd have to consider that. The other thing is we have had periods where we've had at least 16 hours where the load level has been above such that you needed that generation online in order to be single contingency proof. And so I don't see a four-hour or six-hour battery, even, being a potential solution.

Q Battery is not an option.

A Not under the current state, no.

Q What other options would there be?

A One viable option would be a CT, for example, that could run for long durations, if needed. I don't know if there's space or topology or geography qualifies for an SMR, which wouldn't be done by 2028, of course, but I mean, right now I would say CT is the only viable option with respect to replacing the capability for the must-run condition.

Q Okay. I think I know where we are. Appreciate it. One other question for you, and it's a curiosity question. You were asked several questions on cross examination, and you referred to the planning process and mentioned that the Public Staff had initiated a public policy study request to the Transportation -- Transmission Planning Collaborative. I don't recall when that was initiated, but I seem to recall that it was delivered, the results of the study were delivered about this time a year ago. Is my memory correct?

A I believe the report was posted this year, the final report was posted this year around the June time frame because we were going to include the results in the carbon plan as one of the things the Commission had requested us to consider in the carbon plan. And the final report hadn't been generated, and so we weren't able to include those results in the carbon plan.

Q Am I recalling an earlier draft report, perhaps, in the fall of 2021? Was there an earlier initial draft?

A So yes. I mean, we've put a draft of, you know, preliminary results out, and so that may be what you recall.

Q Well, I'll tell you where I'm going. It's a curiosity question, but it came up in cross examination so I wanted to explore it. It's my recollection, at least, that the -- it's probably the earlier draft that I saw -- that the results of that public policy study requested by the Public Staff did not indicate a need for any of the Red Zone upgrades. Is my recollection on that correct?

A So subject to check, I thought there were lines that were identified, subject to check. I thought there were lines identified. I may be thinking about the transitional cluster study, though. But once again, and this is what I indicated to the Intervenors' questioning, is that we need to transition to more of a generator interconnection like study associated with the TPC studies. And, also, if I remember correctly, in that study you were kind of assuming everything was able to be sequenced to be interconnected in one year, almost. And so it didn't really look at that sequence of interconnecting resources as well, but I think the main culprit would be associated with you need to have that study being performed like a generator interconnection study in order to get viable results.

Q And it wasn't done that way.

A That's correct.

Q It was done as sort of like a --

A A screening.

Q -- a fixed point in time. If the resource portfolio looked like this at this fixed point in time, what would the transmission grid need to look like.

A That's correct.

Q Okay. Since neither you nor I have the document in front of us right now, as I say, it was a curiosity question about the Red Zone, and I'll just -- I'll leave it alone for now. It's not -- I don't need to know anymore about it. Thank you.

A You're welcome.

CHAIR MITCHELL: Commissioner Duffley.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q Good afternoon. So I have a curiosity question based on Commissioner Clodfelter's questions regarding generation, the generation replacement process. And my question relates to how far away can a generation unit be away from the switchyard? Like how many miles? Does it need to be right next to the switchyard?

A (Roberts) So there are, you know, a couple requirements associated with generation replacement. One is you have to connect to the same electrical point of interconnection, the existing generation owner basically provides the generation -- the replacement generation -- and I lost my train of thought. I had a third point. I can't remember my third point now. Sorry.

Q Well, I'll ask again, how far away -- and maybe this will trigger it.

A Yes.

Q How far away does a generating unit need --

A Thank you.

Q -- to be away from the switchyard?

A That did trigger. So you can't have a material impact to the transmission system. That's the whole purpose of the independent entity's study associated with the replacement generation.

Q So you have to spell it out a little bit further for me. So my question is related to reliability and any type of radial lines that you might have to build. Let's say there's the option that a generating facility may want to locate 10 miles away from the switchyard, and is that possible and does that cause any type of reliability issues or concerns?

A Yeah. I mean, you introduce that vulnerability with respect to storms, et cetera, you know, taking out that -- I guess, what, a long span, multi-span does to get that generator connected to the same switchyard. So, yes, it would introduce reliability issues. But once again, you know, the generation replacement coordinator would have to study and evaluate to make sure it's meeting the criteria, to make sure there's no material impact to the transmission system associated with that replacement resource.

Q But could you provide redundancy in those lines to reduce that risk, or no?

A I mean, eventually it becomes a new switchyard, right, that you're connecting one to the next. And so, you know, with that it wouldn't meet the requirements that FERC has approved for our generation replacement process.

Q Okay. Thank you for that. So on page 5 you mention SERTP which is, for the record, the Southeastern Regional Transmission Planning process. And I just wanted to go over a little bit of the history, help me remember the history of Order 1000. And if I remember correctly, FERC stated that the North Carolina Transmission Planning Collaborative would not be an acceptable regional planning entity, and the question -- and Duke ultimately joined SERTP for that compliance filing.

My question to you is, did you consider the South Carolina Regional Transmission organization or --

A Yes. SCRTP, yes.

Q Thank you. Did you consider joining that regional transmission planning organization, and why did you choose -- or why did the Company choose SERTP?

A Yeah. So I don't know all the history behind the evolution of the regional transmission planning groups. Subject to check, my recollection is that the South Carolina companies were asked to join SERTP, and they said, no, we're forming our own regional transmission planning group for whatever reasons, and that's how the evolution occurred of Duke being in SERTP and then the South Carolina companies having their own regional transmission planning group.

Q Okay. So it kind of evolved all at the same time, because SERTP had already been created pursuant to 890 --

A Right.

Q -- compliance filing, and so the South Carolina group formed at the same time that your companies joined SERTP.

A For Order 1000 compliance.

Q Correct. Okay. Thank you. And then on page 34 you mention other regional working groups, and you mention the Carolinas Transmission Coordination Arrangement.

A Yes.

Q And could you -- and I think on the direct -- on your direct testimony you stated that you did not attend these -- any type of meetings, but if you can, can you provide more information about this working group? Like how many times does it meet, or does it meet on an annual basis or a quarterly basis, or do they only meet when certain issues pop up between North Carolina and South Carolina?

A Yeah. I honestly don’t know the answer of the frequency of meetings. I know that they conduct reliability studies, and that's primarily it. I think Commissioner Clodfelter asked me that question on direct associated with are they a direct parallel associated with the NCTPC, and the best of my recollection is they've only performed reliability studies.

Q Okay. Thank you.

CHAIR MITCHELL: All right. At this point we are going to recess for lunch. We'll go off the record. We'll be back on the record at 1:30.

(The hearing was recessed, to be continued at 1:30 p.m.)

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 179, 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 3rd day of October, 2022.

Linda S. Garrett

Linda S. Garrett
Notary Public No. 19971700150