PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, September 28, 2022

TIME: 1:32 p.m. - 4:59 p.m.

DOCKET NO.: E-100, Sub 179

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: 29

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

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

E X H I B I T S

	IDENTIFIED/ADMITTED
Transmission and Solar Procurement Panel Rebuttal Exhibits 1 through 3	-/85
CPSA Transmission Panel Rebuttal Cross Examination Exhibit 1 ...	-/85
Public Staff Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibits 1 and 2	121/168
Grid Edge Panel Rebuttal Exhibit 1	171/-

P R O C E E D I N G S

CHAIR MITCHELL: Let's go back on the record, please. We will continue with questions from Commissioners. And you've completed your questions. Let me see if Commissioner Hughes has questions.

COMMISSIONER HUGHES: Yes, thank you.

Whereupon,

SAMMY ROBERTS, MAURA FARVER,

having previously been duly sworn, were examined and testified as follows:

EXAMINATION BY COMMISSIONER HUGHES:

Q. I want to ask a few questions about an example, because that's how I understand things a little bit better when I'm thinking about something. Let's take an 80-meg state-of-the-art solar plus storage facility, okay? Just -- you got it for your birthday, you unwrap it. This is a question for you on the transmission side.

Can you think of a place to put it where it would just be an ideal asset today? So what you'd be thinking about is I'm gonna go ahead and put it here, and after I do it, my life have -- transmission is gonna be easier, it's gonna be better. Transmission system is gonna be stronger, rather than what's it just gonna cost to put it there.

A. (Sammy Roberts) Right. So today, assuming red zone projects or without?

Q. Today.

A. Okay. Today. Without. So a good question. And, you know, you got to consider the different aspects associated with how that resource is gonna function. So for battery storage coupled with the solar, you're gonna have to consider charging. I believe I stated to the Public Staff the other day that, with respect to that charging, we're not gonna study battery storage for charging on peak, because it doesn't really make sense. You know, that -- you want that energy to be delivering to load to serve customer demand on peak. And from a carbon perspective, you know, displacing coal, if you had coal on during that peak.

So, you know, from a transmission perspective, I don't know that I would see solar plus storage as a transmission asset; i.e., deferring transmission, so I don't think I would be placing it to utilize it in that matter. I would be utilizing more so to be able to serve loads.

If I could get decent land availability for the solar, ideally I'd place it near a load center. You limit losses, your battery is gonna be discharging at the peak to serve that load center. So that's -- ideally that's the location that I would see, if I had the land associated with the solar needs.

Q. Does it make a difference if it's -- if it can be charged from the grid? I'm thinking because we're, kind of, settled on that as being, I think, during this hearing as the ideal, so it can get charged from a grid, or does that make a deference?

A. Yes. From -- with respect to grid charging, once again, we'll be studying that grid charging and making sure that the transmission system can support that. So yeah, you would have to look at where that energy, if it weren't provided by solar; i.e., cloudy days, rainy days, snowy days, if it wasn't provided by the local solar, then where would that energy come from.

Q. I hate to be too hypothetical, but I'm gonna go ahead and say you're given this, it's your birthday gift, you have to install it within the next year.

Can you think of a place on the transmission grid that would be your -- like your ideal place? Or can you think of what you would do to find out where that ideal place is? So it's a question at least a little bit more on the benefit side than just how can I minimize my cost.

Can you -- you know, what would you do to just go ahead and find that ideal spot where the asset would be somewhat of a benefit?

A. Once again, if the land availability was there, it would be near a well-connected 230 substation that was near a load center.

Q. Okay. And, I mean, would you have to do any more -- we heard -- we heard that, with it being able to be charged by the grid in going out, it might require actual modeling as a source, you know, not -- I mean, what kind of modeling would you have to do? Would you have to do a lot of modeling to, kind of, confirm that's a good spot?

A. Yes. I mean, we'd have to look at it as, once again, a load, but not at the peak. I think, in our practice, we've got some load levels defined at or below this load level it can be charged, or it will be studied for charging. And then the discharge at peak. So you'd look at discharging from that facility during winter peak, you'd look at discharging from that facility probably during solar peak as well as output -- at solar peak, probably output at net demand peak.

Q. So, you know, I'm assuming that that's all done through some sort of power flow modeling.

And do developers have the same access to that same kind of modeling as you had? I don't know if you were here when I asked --

A. Yes.

Q. -- a question about what's the single thing that might speed up the interconnect.

So if we wanted developers to go and find that same that you picked, do they have all the same information that you have?

A. Yeah. So I know they have access to the -- like the DISIS study, for example, this time around, or past generator interconnection studies. I know that we post -- we would post those studies -- I think this was true for the transitional cluster study. We would post those study cases where the developer or anyone, a consultant, whoever could access those cases, and they should be able to take those and replicate the results.

I heard what Mr. Norris said, but they should be able to take those cases and replicate the results.

They would need to have the PowerGEM TARA application, which is what we used. But having that and having those cases, they should be able to replicate the results.

Q. But if they didn't want to -- I'm sorry to push, but if they didn't want to replicate and they just wanted to duplicate and do it -- be able to go do it themselves, so they were identifying on their own, kind of -- so when, you know, put it through the study, it was -- there's no surprises.

A. Right. If -- go ahead.

A. (Maura Farver) Well, I was going to say, I think you're hitting on a really interesting conundrum, that, if a particular location on the grid is flagged as a great location, then lots of projects are going to want to site there. So then when you end up in a cluster, suddenly you have a lot of projects right there, and that spot that used to look great probably won't look so great anymore.

And so that's why it's very tricky to provide that kind of guidance as to optimal placement in the way that you're suggesting, because as soon as you make that announcement, then it's probably no longer an optimal spot, because you can exceed the capability there easily. It's a difficult problem.

Q. So we're stuck? We can't do what everyone would agree would be -- make the most sense?

A. (Sammy Roberts) In the past, that guidance has been provided through -- since at least 2018, that I recall, it's been provided through red zone maps. And that has changed some over time, it's expanded some over time. But we have provided that guidance with respect to if you choose to locate in this area, then you're probably gonna incur network upgrades, and it may take a while to get those network upgrades in service.

Now, that's not to say if you locate -- if you request interconnection outside of that red zone, there won't be network upgrades. In fact, I've stated in testimony there probably will be some network upgrades. And it's dependent on volume and location as to what those upgrades are.

Q. I know -- I appreciate that. I know I'm simplifying it. But it does seem like those maps might not be enough to really actually find where is gonna be the ideal setting.

And the follow-up is getting back to this price signal question. So this would seem like it would be a facility that we would support more than some of the other facilities that we've talked about or you could imagine that were gonna be in places not nearly as beneficial.

Do we send the right price signal to that kind of project? Does the RFP process benefit that type of project?

A. (Maura Farver) I think if we ever identified a particular area of the system where we felt we really needed that power, then we could direct a general area. You know, if -- so I think that there are examples in other states where they have local RFPs, and in particular -- to meet particular needs.

But in the case of solar, usually we're driven so much by land availability and trying to have the right geography/topography, and just the amount of area, that I don't think that predetermining specific locations of where solar would be optimal on the grid is very helpful because it's so dependent on the land availability really.

Q. Okay. I won't ask you to go through the same exercise with just a standalone battery where land wasn't quite as much of an issue. But you could think about what the answers would be where we took land out of the equation. But it really helps me to kind of figure out where we're going. That's all.

CHAIR MITCHELL: Okay. Commissioner McKissick?

COMMISSIONER McKISSICK: Actually, I think the panel's done a great job in responding to questions I had in the back of my mind, particularly as it related to public of staff issues. So I don't have any further questions.

CHAIR MITCHELL: All right. Commissioner Kemerait?

EXAMINATION BY COMMISSIONER KEMERAIT:

Q. Yes. Good afternoon. Ms. Farver, I've got a couple of questions related, I think, to your statement on page 6 that you already quoted or read on line 15, which states, "To date, these red zone upgrades have created insurmountable cost hurdles for developers. One or two projects being asked to bear the upfront costs" -- excuse me, "the upfront burden of that cost."

And so my question's gonna relate to that and then also some information that you provided to CPSA's attorney in response to his questions. But for future solar procurements after the 2022 solar procurement, my understanding is that there would be potentially two ways to allocate the transmission cost that would be -- that a generator would trigger for those transmission upgrades.

And the first one you, I think, explained a response to questions would be that in the bid evaluation process in the solar procurement, that the costs would be allocated. The costs that were assigned to the generator in DISIS would be evaluated in the bid process, correct?

A. (Maura Farver) Correct.

Q. And then the second possible way that I don't think you talked about, but I'd just like to see if this is correct, is that there would be the potential that the generators would be responsible for paying for those costs themselves. They wouldn't just be allocated, but the costs that are assigned in DISIS, the generators would have to pay for in the solar procurement.

Is that another -- another way that it could be handled?

A. Correct.

Q. Okay. And then, I guess in response to the statement that you made on page 6, and then we heard testimony that about 3,500 or 3,600 megawatts of projects that have bid into the 2022 solar procurement are located in the red zone area. And I recognize that you said that some of the projects may drop out of DISIS before -- before phase 2 of DISIS, so that number is not certain for sure.

But with this greater number of megawatts in projects, have you done any analysis about whether these projects now would be able to pay for their network upgrade costs, because it would be -- those large costs would be shared among a greater number of projects, or at least a greater number of megawatts?

A. I have not done an evaluation to that effect. I think we'll have to wait for the DISIS phase 1 results before we'll see how those costs are spread over the generators that are currently in this cluster. I think I'm missing the other part of your question.

Q. So that is my question. So after you look at the results, is that something that you will be considering or is that an analysis that will be -- that will be performed?

A. So I don't know that we currently have any other mechanism to distribute those costs that are triggered, except what's designed through the interconnection process or through proactive transmission planning. So I think those are really the two avenues that are available to us. And the reason that we are recommending moving forward with the red zone upgrades is because that brings us to a scenario where, ultimately, the costs are spread over a much larger swath of projects and we don't fall into the same pattern of costs falling to not enough megawatts and not moving forward. Costs falling to not enough megawatt and not moving forward. And so that is the, as I understand it, avenue available to us today to move these forward.

And over time, they will be spread over many megawatts, but today we don't have perfect foresight as to how many exactly megawatts there will be.

Q. And that's helpful. I think the one thing that I would like to some clarification about is that, if the red zone upgrades are approved by the NCTPC as the public policy projects, if that were to occur, then they would not be included in the base plan or the baseline. And so then they would not be allocated among the projects in the solar procurement. So I'm seeing a little bit of a disconnect here, so maybe I'm misunderstanding it.

A. Let me see if I understand your question correctly. So if they're approved by the NCTPC and they move forward, for the '22 procurement it was our understanding from the Commission's order that they should be part of the evaluation for the '22 RFP. I think that how they're incorporated into the evaluation for '23 and beyond is still to be decided.

And so it might be that, if they are approved and they're in the baseline for a '23 DISIS, that there might be something to design in the RFT such that it's not just zero assigned to those red zone projects, but that there's some cost reflected in the evaluation process to recognize that there was a transmission cost associated with it. Is that what you mean?

Q. That's very helpful, to understand that there might be a mechanism for some sort of allocation even if they're approved by the NCTPC. So thank you.

A. That would be new territory for us, but I think there's certainly much that we still have to design for our next RFP.

Q. Okay. Thank you.

CHAIR MITCHELL: All right. Any other questions, Commissioners? You may.

EXAMINATION BY COMMISSIONER HUGHES:

Q. Is it possible that the rankings for the RFP could be really different, depending on whether you take into consideration -- I think it is, but whether you take into consideration the transmission cost?

So if -- if we had -- if take that off the table and just rank the -- rank the prices and then we -- you have that ranking, and then you add the transmission and you have a different ranking, which ranking will you use, just the second ranking?

A. The way the 2022 solar procurement is designed is that we would use the ranking with transmission costs included.

Q. Okay. So if there was -- had been a decision midstream or -- to actually go ahead with the red zone, then the result of the RFP is we are no longer taking in the low-cost projects by the time they get connected?

A. It would have, you know, potentially changed the ranking because projects located in the red zone would -- if the red zone upgrades were already approved at this point in time and had been approved prior to this RFP, if they were, you know, already included in our local transmission plan, then we would not be assigning those costs to generators in DISIS.

And so to that extent, it would have an

impact on what the ultimate costs are assigned to those generators and it would theoretically change the ranking.

Q. I mean, it seems like, if that's the case, the outcome is not gonna be the least cost for customers, because they're gonna -- they would be paying the socialized red zone costs, and then now they are no longer getting what competition did for driving down the price, because it's -- the ranking is based on -- so customers, it would seem like, are not gonna get the actual least cost of the projects.

A. (Sammy Roberts) So if put a developer hat on, and I know that transmission cost is not an obstacle, bidding on a project in the red zone, my bid is probably gonna be lower to ensure it's competitive and it wins.

A. (Maura Farver) I'd also add that things were moving very quickly to get the '22 RFP off the --

Q. No, no, no, I understand.

A. Well, I mean, this is -- if the red zone upgrades are approved by NCTPC and, sort of, ready for the baseline in '23, all of these future projects will show that as part of their baseline. So it's not a continual --

Q. Right. It's just the 2022.

A. -- issue, necessarily, it's, sort of, a limited slice of this '22 RFP wouldn't have had the foresight of knowing that those upgrades were going to be paid.

Q. That makes sense. Okay. Thanks.

EXAMINATION BY CHAIR MITCHELL:

Q. Okay. So I just have a few to follow up on the discussion that you all have been having on the red zone projects as well as procurements. Because I -- I thought -- I'm just confused at this point and I -- I don't -- I'm hoping I can not be confused by the time I get out of this hearing room. And that may -- that's my plan. And we all know --

A. (Maura Farver) I hope we can help.

Q. Okay. So the way I understand what the Companies are asking of this Commission in this proceeding is that the Companies want us to indicate that the red zone projects are needed to enable the solar targets identified in the portfolios that are included in the Carbon Plan.

Do I understand the Companies' request correctly?

A. (Sammy Roberts) That's -- excuse me, that's correct. We're requesting acknowledgement that the red zone projects are needed to be able to execute the Carbon Plan.

Q. And so if we give the -- if the Commission gives the Companies that acknowledgement, then what?

A. As stated, with respect to the NCTPC process, we've got to present the supplemental studies to the TAG, and then, end of the year, present the local transmission plan draft. The Commission order should coincide with around the time the NCTPC publishes a final -- final report. And so, you know, we would hope to have that Commission acknowledgement to use to bolster that yes, these need to be in the local transmission plan. Because until that final report is published online, they're not in the local transmission plan.

Q. So if they're in the local transmission plan, assuming that the NCTPC votes to include them in the local transmission plan, how does the Company act on that?

A. If they're in the local transmission plan, they're considered part of our transmission additions plan at that point.

Q. And so the Company -- I'm sorry, I didn't

mean to interrupt you.
A. No worries. They become projects as part of the transmission additions plan.
Q. So the Company would construct, and it would be capital investment just like any other capital investment the Company makes?
A. That's correct.
Q. Okay. Before you-all came back on rebuttal, I thought I understood your testimony to be that the -- if the Company -- if the Commission were to give you this acknowledgement and the Companies were successful in convincing the OS -- the OSC; is that right -- to vote on -- to vote to approve the projects, the projects would be included in the local transmission plan or the baseline for the 2022 procurement; did I misunderstand that?
A. So they would become part of the baseline for the 2023 --
Q. Okay.
A. -- DISIS.
Q. Okay.
A. (Maura Farver) There might be --
Q. 2023. So for the next DISIS window; is that right?

A. (Sammy Roberts) That's correct.
Q. Okay.
A. I think Ms. Farver has a clarifying.
Q. Okay. Please, Ms. Farver.
A. (Maura Farver) Correct me if I'm wrong, that when a transmission upgrade is part of the local transmission plan, it would -- the cost of that upgrade would then not be assigned to a generator in their ultimate interconnection agreement. And so I think there's a timing question here of when exactly that becomes official in the transmission plan.
The -- I don't know if it would be in time for a phase 2 cost estimate to assign that cost elsewhere or if it would still be on the generator, but by the time the interconnection agreement is signed in Q1 early 2024, it may have become a contingent facility at that point, in which case the cost would not be assigned to the generator and the ultimate interconnection agreement.
Q. Okay.
A. Mr. Roberts, please correct me if I've misstated that.
A. (Sammy Roberts) Yeah, so, I mean, all that sounded correct in a normal world, but we're not in a

normal world. And so the way the 2022 procurement is structured, it seems like we would have to move forward with evaluating these projects, and the costs included would consider the red zone expansion plan projects.

Q. Okay. So -- okay. So --

A. (Maura Farver) So I may have misspoken in that the costs won't be assigned elsewhere until the 2023 DISIS begins.

A. (Sammy Roberts) Right. That's my understanding.

Q. So then all of those red zone-dependent projects that are participating in 2022, it's likely that they're not gonna move forward unless --

A. (Maura Farver) It will depend on how many of these upgrades an individual project hits and what the allocation is.

Q. So there's a chance that before -- I'm just -- I'm trying to work out timing here. So there's a chance that if -- if a project in the 2022 -- if a bid in the 2022 procurement is dependent on a red zone project, that it could be assigned costs associated with that red zone project if you-all haven't been able to add the red zone projects to the baseline?

A. I think it --

Q. Given the timing of our order and your ability to get it through?

A. I think it is a question of timing as to when the official approval comes, when the cost estimates are provided, and when the reports and the ultimate interconnection agreement is executed.

Q. Okay. I'm just trying to figure out. We have watched -- we watched CPRE tranche 3 fall apart. That's my word, just a simple shorthand. Then we kind of watched the transitional cluster -- you know, we all know what happened to the transitional cluster. Then are we gonna say the same thing happened with 2022 if we were to -- well, I'm just -- that's a -- don't even answer that question, it's just a -- it's just a sort of thought that I have in my mind.

So for -- you've done -- I appreciate your hanging in there and answering these questions. I'm just trying to get through all of this. But the -- and you've talked -- you've responded to questions from Commissioners about -- I think Commissioner Kemerait said post 2022 there would be two ways to deal with -- again, these were my words, deal with upgrade costs. Upgrade costs, specifically the red zones.

And you mentioned including them in the bid evaluation process so that each bid is allocated, you know, a certain percentage of upgrade costs that it triggers. Or the generator could be responsible for paying whatever percentage of the upgrade costs it triggers.

Did I understand that correctly?

A. I think that was a good summary.

Q. Okay. Is it -- but why is that just post '22. I mean, couldn't that still happen in the 2022 procurement? Couldn't that same approach, either of those two options?

A. I believe it would require the Commission changing the stance that it shouldn't be included in the baseline. So we've been designing the '22 RFP based on the Commission's order that these upgrades would not be in the baseline, and so I imagine that would have to change in order to change anything to the '22 RFP.

Q. Okay. And I guess I didn't understand Commissioner Kemerait's question to be assuming the projects were included in the baseline. I just assumed -- was that your question? Okay. I understood her question to be how are we gonna deal with network upgrade costs going forward.

Because, you know, I guess my -- my question at this point is, we've been using the world "allocated," and we -- and probably the conflation here is mine. We allocate -- we could allocate costs to bids for purposes of determining their competitiveness -- that's kind of what Commissioner Hughes was getting to -- or we can ultimately allocate costs.

And in certain respects, you know, we've been through this in many different proceedings now where we understand, at the federal level, costs are allocate -- we're talking about federal jurisdictional costs, they're allocated in accordance with the Companies' OATTs on file with the federal government. But -- but there are also costs -- or there are state jurisdictional costs that aren't subject to that federal allocation process that's established at the federal level.

Do I understand that correctly? And do I understand that costs -- let me ask a non-compound question.

Do I understand that we've been talking about that costs could be allocated either to a bid for evaluation competitiveness purposes, or costs -- and/or costs can be allocated to the generator for payment purposes? I'm just talking about we can use term in one of two ways.

A. (Maura Farver) Yes, I agree, we've been talking about it in both. That sometimes we're talking about allocation just in the bid evaluation --

Q. Right.

A. -- and sometimes we've been talking about allocation in terms of assigning that cost to the generator for them to pay in order to interconnect.

Q. For them to ultimately pay. And I'm sorry I spoke over. You let me --

CHAIR MITCHELL: I'm sorry, Joann.

Q. So -- okay. So going forward, we just need to be careful when we use the word allocation, if we're talking about allocating the bid for the purposes of determining its competitiveness, or allocating to the ultimate payer.

My question for this panel is, so if we give the Company what it wants, what it's requested on the red zone, which is an acknowledgement that they're needed to move towards the Carbon Plan obligation -- 951 obligations the Company now has, does that -- does the Company take from that any implications or does the

Company become obligated in any way with respect to then how it recover those -- recovers those costs? Meaning then is it obligated to recover those costs from its ratepayers, or could it turn around and devise a cost allocation scheme or paradigm that could involve recovery from generators? Direct assignment approach.

A. (Sammy Roberts) I don't know of any cost allocation methodology that is currently in place --

Q. Okay.

A. With respect to assigning those to a generator after they're approved and in the transmission additions plan not associated with a specific generator interconnection.

A. (Maura Farver) I'm not aware of a different way that we could assign those costs, and that's probably a legal question or legal interpretation as to is there some other mechanism for cost allocation aside from the generator or through the local transmission plan. I don't know. I'd want to check with FERC attorneys and others.

Q. Okay. So I'll ask my question one more time. I understand what each of you is saying. I'll ask it one more time, because my question wasn't clear.

If we approve -- or if we acknowledge that the red zone projects are needed, and then the Company moves forward to -- with the NCTPC process, gets the approval it needs there, and then includes the -- includes those transmission projects in its transmission addition plan and ultimately builds them, is there anything keeping the Company from recovering -- if it's directed to do so by the Commission, recovering certain of those costs from generators?

A. I think that's a legal question that I don't know the answer to.

Q. Okay. Okay. That's fair. That's fair. And has the Company given thought to how we -- if we move forward with the red zone projects, as the Company has requested and is planning to do based on testimony y'all provided and in the Carbon Plan itself, how do -- how can the Companies, and therefore the Commission, be certain that customers are getting the most competitively priced solar that there is? And by "competitively priced," I mean taking into account all of the costs that those specific facilities are imposing on the network.

A. As a hypothetical, I think there's probably an opportunity in future RFPs to include a piece of the evaluation to take this into account. I don't have a proposal or details worked out today as to what that would look like. But I think that that is something that could be designed for and included in an RFP evaluation.

Q. So post 2022?

A. Yes.

Q. Okay. So 2022, the plan would be for the Company -- again, make sure I'm clear. The plan would be or the Companies' plans or proposal is that, assuming again the Commission acknowledges they get through the NCTPC process, that -- that while bids may be allocated in the bid evaluation process, percentages of the upgrade costs that the bid triggered, those costs ultimately are not gonna be collected from the generator, but they would rather be collected from ratepayers at large?

A. If they are approved at the time, then yes, the assumption would be they would not be paid by the generator.

Q. And I understand the timing issue. Assuming the timing works out such that they could be included in part of the 2022 process.

A. I think that's right.

Q. Okay. We haven't talked much about the solar reference cost. In fact, I'm not sure if anybody's -- if it's been brought up. I don't think an intervenor has brought it up. And I'm just curious, and if you're not the panel to address this, y'all don't hesitate to let me know.

We -- in the CPRE tranches, the -- pursuant to this statute, the bids were subject to an avoided cost -- we think of it as an avoided cost threshold. The bids were evaluated for competitiveness against the then in effect avoided cost, and that included considering network upgrades in conjunction with the cost of the -- you know, the output of the facility.

And so CPRE actually, kind of, did, in my mind, what you guys are -- what I've heard you testifying to, Mr. Roberts, in that it considered transmission costs and generation costs together. At least, sort of, in my simple mind. The -- we -- we are now beyond -- we're looking beyond CPRE to this 2022 procurement and then future procurements that the Companies will have to conduct to comply with its obligation -- their obligations under the legislation. And, you know, we have been presented with this concept of the solar reference cost.

And how -- help me understand how the solar reference cost will function as an -- will function like the avoided cost, because with the avoided cost threshold, we could have some confidence, and a pretty high level of confidence that ratepayers were protected or getting a good -- getting a, you know, most competitively priced solar output.

Are we there with the solar reference cost?

A. Subject to my colleagues on the modeling panel's expertise, I think that the solar reference cost is a good mechanism for the world that we're in now. We're using the best information we have available to create that forecasted cost, and there is a transmission cost expectation built into that solar reference cost.

And so what we designed in the '22 RFP was a mechanism to check and adjust inflate, essentially. So by having this deviation from the solar reference cost leading to change -- a change in the volume potentially, that was our way to check and adjust when we were, sort of, in real time.

Q. Okay. Okay. And there is also the downward bid adjustment opportunity in the 2022 procurement. And can you help us understand the function of that --

what does the Company expect to see as a result of that part of the process?

A. Do you mean the bid refresh?

Q. Yes, the bid refresh.

A. That was an important consideration in this RFP, because there was a lot of uncertainty about what was going to happen with the tax incentives. And so we knew there was a decent chance something would change, but we didn't know when or how it would change. And so this, essentially, allows an opportunity for bidders to sharpen their pencils and come back with a more competitive price if they're able. They don't have to, but it does offer that opportunity. And so I think that's really helpful for customers to make sure that they're getting the best offers available in the RFP.

Q. And we anticipate -- let me ask the question this way.

Do the Companies anticipate that by the time the bid refresh period opens, window of time opens, that there will be sufficient understanding about the tax credits and availability of the tax credits, that those can be -- that that revenue can be taken into consideration for bid refresh purposes?

A. It is unclear to me what level of detail we'll have from the IRS at that point in time.

Q. Okay.

A. But certainly the more time that goes on, the more clarity we should have about how those benefits can be achieved.

Q. In my mind, you know, those are critical benefits that should inure to ratepayers.

So do we need to move that bid refresh window to ensure that the bid refresh process can take into -- take -- can sort of put some pressure on to --

A. I think the problem we run into is there's never a perfect time. And so if we delay this, there will be other uncertainties. We specifically designed the '22 RFP to align with all of these very prescriptive dates in the DISIS process. And so pushing back the bid refresh window -- we pushed it back as far as we thought we could by having it be in early April, because we're trying to announce the winners contemporaneous with the phase 2 results.

And then there's a very prescriptive window for interconnection about needing a signed-off take agreement to keep moving forward. So we're stuck between these very set dates for the interconnection process. So I don't know that we would have wiggle room to change the bid refresh date without causing a lot of disruption for the rest of the evaluation.

Q. Okay. Okay. Mr. Roberts, did you have a chance to review Exhibit D to the CPSA comments that were filed in this docket?

A. (Sammy Roberts) I may have, but I don't recall Exhibit D.

Q. Okay. I asked Mr. Norris about them yesterday. I think it was yesterday. They -- the -- it's an exhibit that was prepared by -- or on behalf of CPSA, and Mr. Norris testified that Cypress Creek Renewables had been involved in the development of the analysis. And it basically is a GIS analysis of acreage and the two -- in DEP and DEC's service areas in both North and South Carolina. And it identifies these clusters of viable, you know, acreage for solar development.

CHAIR MITCHELL: Do you-all have a copy you could put in front of him, please?

THE WITNESS: (Sammy Roberts) I thought I may have a copy of it.

Q. And if you haven't -- if you haven't reviewed this or had an extensive amount of time to think about it, I'll keep my questions very brief.

A. (Maura Farver) What was this from again?

A. (Sammy Roberts) I can recall. It's a map with like the number 6 zone in DEC.

Q. Yes, yeah. Do you remember this? I'm hoping y'all's counsel can pull something out of the box over there.

MS. KELLS: I think we have it.

Q. So the -- my question for you-all is this. Assuming you've looked at it -- and here comes your counsel.

But do you have any thoughts about -- do you have any thoughts about transmission, the state of the transmission system in these areas? I mean, other than obviously the red zones that are located here.

A. Right. So number 3 includes a red zone, itself. Number 2, that's where we were talking about the same corridor as the offshore wind transmission. And so, I mean, there's probably some capability there, but it probably won't be long before 115 kV line will show overloaded. So you'll probably run into a red zone there being created before too long, looking at the DISIS.

Number 5 is red zone. Number 6 is red zone. Number 4 is red zone. So that leaves number 1, and I think topology and land availability is an issue in the number 1 region.

Q. Okay. Okay. The -- you, sort of, gave me my -- answered my questions about transmission availability or transmission -- state of the transmission system.

But the -- if we think about, on a going-forward basis, integrating transmission planning with generation planning as the Companies grapple with the generation they're gonna have to bring online, is this a way to start that process, looking at acreage that's suitable for solar development and then identifying -- you know, figuring out what the transmission system looks like in those locations?

I'm just trying to get a sense of how to distill your recommendation of integrating planning for the two -- for generation and transmission into some action items or some concrete steps that we can think about.

A. Right. So I mean, the one thing that we had to -- we were able to rely on with respect to knowing the red zone projects would be used and useful and allow us to execute this Carbon Plan is -- are the prior generator interconnection requests. So we're not gonna have that going forward, right? We had the 2022 DISIS which has, what, 5,000 megawatts, 4,900 in the red zone. So we had the 2022 DISIS that informs us a little bit too with respect to a lot of solar and DEC and DEP wishing to interconnect.

I mean, as far as studying it from a zonal approach, and then -- I'm forgetting what Mr. Norris recommended. But would procuring from a zonal approach, is that what you're asking?

Q. No. I'm just -- I mean, that's one place where you could go if you -- if you start with the assumption that should we be looking at area where there's suitable land for solar development. Because one of the things that the Commission has been hearing is there's a limit on suitable land. And the most suitable land for solar development is in the red zones, that's why they're all there and that's why they continue to show up there.

A. Right.

Q. So, sort of, getting beyond the red zone, looking out into the future, should we start with where is land? Where is land suitable for solar development, and then identify the most efficient places to locate on the transmission system, sort of, when you overlay transmission system with that land?

A. Yeah. I mean, can we can look at -- kind of like with the NCTPC -- NCTPC wind study and look at, you know, different capabilities of injection into the transmission system at various points. And then overlay that injection capability with the land availability with the map. I forget what figure it is, but there's a figure in the testimony that shows the high solar viability from a land perspective, parcel perspective. So you could overlay that injection capability with land availability.

Q. Okay. Okay. And then -- and then identify locations on the grid that would be conducive to lower-cost solar development when you consider both the cost of generation and the cost of the transmission?

A. Right. I mean, ultimately, it gets down to the, you know, developer saying I have a land lease at that area, whatever. I mean, they -- they would have to select and bid in that location and megawatt size to take advantage of that screening, so to speak.

Q. Okay.

A. I don't know the proper way to make that happen, that piece.

Q. Okay. All right. I think that's all for me.

Let me just make sure.

Mr. Roberts, I just want to make sure I'm clear on one thing. Tyler -- Tyler Norris yesterday testified that developers didn't have -- couldn't replicate the power flow modeling. And you just testified in response to one of the Commissioners that you didn't -- that you didn't understand why developers couldn't replicate.

A. Right.

Q. Is that what you were talking about?

A. Yes.

Q. Were you talking about the power flow modeling?

A. Yes.

Q. Okay.

A. He should be able to take the posted cases or the DISIS or transitional cluster study and be able to replicate those results.

Q. Okay. Assuming that they have some sort of --

A. It's a -- called TARA, T-A-R-A, application by PowerGEM.

Q. Okay. And is that a -- is that an obscure piece of technology, or would it be your -- a reasonable assumption that a sophisticated solar developer would have access to that?

A. If they have, you know, a little bit of power flow skills, transmission-planning skills, they can probably use it or learn to use it.

Q. Okay. Understood. All right. I think that's all I have. Thank you both for responding to my questions.

COMMISSIONER HUGHES: Every time you ask, I need to follow up.

CHAIR MITCHELL: Well, Duffley has beaten you, so Duffley.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So can you remind me, with respect to the 2022 DISIS RFP, is it similar to the CPRE process where the bids that come in do not reflect paying for the upgrade -- network upgrade costs, but rather, those network upgrade costs are assigned afterwards for bid-ranking purposes?

A. (Maura Farver) We designed the '22 RFP slightly differently. So for the PPAs, there is what we've called a part A and a part B bid price. So part A is just as CPRE was, that would include interconnection facilities but not any system upgrades.

Part B is an adder for what that developer would be seeking in dollars per megawatt hour per million dollars of system upgrades that are assigned, and that would be additive to their part A price.

Q. Okay. Thank you. And that is -- the two-part bid is before they know the assignment; is that correct?

A. Right. And part B was designed that it's per million dollars of upgrades. So that if it comes in at 5-, then it's scaled; if it comes in at $10 million, then it's scaled.

Q. Okay. Thank you for that.

And, Mr. Roberts, do you remember my examination or questioning, or however you want to say it, discussion with you about the hypothetical that even -- the hypothetical the other day was, even if you did not have all of the generator interconnection requests for purposes of this hearing, would -- and Duke had to build 100 percent of the solar that Duke feels is needed to meet the Carbon Plan, where did you state -- did you state that the red zone was an area that Duke would choose?

A. (Sammy Roberts) Yeah. I mean, once again, due to the land -- land availability, parcel size --

sorry. Due to the solar viability in that area where we could have larger solar facilities per interconnection, I definitely believe the red zone would be the location that we would look to for putting these large solar facilities to meet the Carbon Plan.

Q. Okay. Thank you.

EXAMINATION BY COMMISSIONER HUGHES:

Q. So it's obvious there's a little bit of confusion about exactly the specifics of the RFP. So I just want to make sure I understand it and you two are at least in agreement. That whether it's 4,900 of -- we're sitting on these exciting 4,900 megs of bids, right, that we're all excited about, was it clear to all of the bidders that they were going to pay their A bid plus some transmission costs no matter what?

A. (Maura Farver) So the part B bid is for an evaluation to decide whether the utility will pay for the upgrades or whether the bidder will pay for the upgrades. And so this is explicitly written into the RFP document, and we had stakeholder meetings about that as well, so it should be well understood.

This suggestion -- suggestion actually came from our independent evaluator as we were trying to ensure that it was least cost for the utility to pay for those network upgrades as we did in CPRE. This seemed like the right mechanism and was their suggestion for how to verify whether it was more cost effective for customers for the bidder to pay for the upgrade or the utility to pay for the upgrade.

Q. But did I hear you, in responding to Chair Mitchell, say that, under the mechanism we have, there's no permitting option B? That at least in the red zone, that for this procurement -- that's where I was confused. For this procurement, what's going to happen is there's going to be an option C, which is their bid and the actual transmission upgrades that are incurred with whoever is left in the accepted bids?

A. Can you repeat that, because I'm not sure I understood your question?

Q. So somebody bid, they have a bid, that's A. Bid B is essentially assuming that you pay for the red zone, it's socialized, so it's -- right, and they know what it is. But I thought you said a moment ago that there's no cost allocation method that you have now available that they would actually pay B.

They're actually gonna pay another price, which is their bid plus the actual upgrade cost, even if they're in the red zone, because the red zone wasn't accepted before the RFP?

A. I think I understand. Go ahead.

Q. Okay. Yeah, I'm sorry --

A. I think I understand.

Q. Yeah.

A. So the part B is not a flat, you know, millions of dollars. It's dollar-per-megawatt-hour per million dollars of upgrade. So that bid, if it were in the red zone, and let's say it hit everything and had a very high price tag associated with it, so that slider bar would go up. So if it's $30 million of upgrades and it was a dollar --

Q. Yeah, I'm with you on A and B, yeah. Excuse me.

A. And so if the red zone upgrades are approved by NCTPC and that all happens by, I think, May when the phase 2 report would be issued, then for our evaluation, we would use that $30 million of network upgrades as we ranked that bid. But since their ultimate interconnection agreement would not have the $30 million in it, because it would get paid for in a different way, they would not have the part B as an adder. So if the $30 million went down to one --

Q. Okay. I misunderstood your -- okay. Okay.

That makes sense. I thought you were saying that even if we -- even if the red zone got approved in May, it doesn't matter, because it wasn't made out that way in the RFP. That's what I thought you said. I misunderstood.

A. For the evaluation. That was kind of getting at the distinction between the evaluation.

Q. Okay. But for the cost allocation --

A. I think that's to be determined with the exact timing.

Q. Right. And if we don't -- okay. I just misunderstood. And if the red zone is not part of the final, then there is going to be this point C that is the -- their bid A plus the actual cost of the red zone?

A. It will be -- yes, I'm sorry. B times whatever that cost is added to A, yeah.

Q. Okay.

CHAIR MITCHELL: Any additional questions? Go ahead.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Mr. Roberts, this may be a question for the Long Lead Resources Panel, but you're the transmission guy and I just remembered that, if I let you get away and then they refer a question back to you, I'm stumped.

A. (Sammy Roberts) I'm on the Reliability Panel too, so.

Q. Oh, that's right. But this is not a reliability issue, really. It's not a reliability issue. So let me just ask generally.

Do you have any understanding about the transmission pathway from this being looked at from a landing point for offshore wind at Emerald Isle up to an injection point in New Bern? Do you know anything about the transmission pathway there?

A. Yes, I do.

Q. Well, then let me ask you the question, then. In the Long Lead Resources Panel direct testimony, we were told that one of the pathways that is being looked at is to land -- from Carolina Bay to land it somewhere around Emerald Isle, and then to bring it up to New Bern for injection into the grid. And that -- from the map I'm looking at, that looks to be about 70 kilometers of onshore transmission.

Would that be an existing transmission right-of-way, a pathway that you'd upgrade? Would it be a greenfield transmission line? What would that pathway be?

A. Yes, sir, that would be new right-of-way.

Q. New right-of-way?

A. Yes.

Q. And what would be the sizing on that potential transmission line?

A. Well, it would be a 500 k -- 500 kV DC line, if I'm correct.

Q. 500 kV DC?

A. Yes.

Q. I'm glad I asked you the question. Thank you, sir.

CHAIR MITCHELL: All right. Questions on Commission's questions? Start over here.

MS. GRUNDMANN: Okay. We're gonna go out of order. This is Carrie Grundmann for Walmart, because I want to follow up on pretty much every Commissioner's question to make sure that I feel like I understand everything we've just talked about about transmission.

EXAMINATION BY MS. GRUNDMANN:

Q. So I think Commissioner Hughes clarified for me what happens if -- for purposes of the 2022 solar procurement, if the NCTPC approves the inclusion of the red zone projects in your local plan, then any of those upgrade costs would be assigned for purposes of allocation to the generators, but would not be paid by the generators, but would instead be recovered from customers through some separate mechanism; is that correct?

A. (Maura Farver) Very close.

Q. I'm so close. Okay.

A. Just in the term. Just in the term. And I think this is getting to that using the term allocation if we're talking about for evaluation of the RFP or for actually having the generator pay it.

Q. So that's why I used the word "assign" versus "allocate" to try to differentiate.

But I'm just saying if the -- if the NCTPC approves the red zone projects and they get added to the Companies' local plan, then generators will not pay those upgrade costs, but they would be assigned those costs when you evaluate them for competitiveness of the bids?

A. That sounds correct.

Q. Okay. Now, if the NCTPC does not approve the projects by the time of the phase 2 study, then those generators will be assigned the cost of the interconnection and would be required to factor those into their bids?

A. They would be required to pay for those costs as part of their interconnection agreement. The bid design has this part B, and so they've already bid what is their adder per million dollars of network upgrades.

Q. What do they need to receive if they are assigned those costs for every million dollars?

A. Yes.

Q. So how much more do they need to earn per megawatt hour if so many million of dollars of costs are assigned to them?

A. That sounds right.

Q. Okay. So now I think I understand. Now, let's talk 2023.

What happens if, after the phase 2 interconnection requests are all signed for 2022, the NCTPC approves the Red Zone transmission projects, then who pays for them?

A. So it would still be distributed as other transmission upgrades are. It would not be specifically assigned to those generators in the interconnection process. But I think what Commissioner Kemerait was getting at is how do we account for that or acknowledge that in our ranking process.

Q. Well, hold on, let me come back to that, because I just want to make sure I understand.

So hypothetically, all of the red zone transmission upgrade costs could be triggered by the bids that were submitted in the 2022 solar procurement, correct?

A. Hypothetically.

Q. So -- but it's also possible that some do not, but that in the 2023 procurement, new projects would get the benefit of upgrades that weren't triggered by the 2022, but that are subsequently included in the baseline for purposes of the 2023 procurement? Does that question make any sense? And I can try to reframe it.

A. If you can repeat it, that would be helpful. I think I got lost in the details.

Q. Me too. If the 2022 solar procurement bids trigger some but not all of the red zone upgrades, and let's just assume that those generators have to pay those costs, but then subsequently, the NCTPC approves the entirety of the red zone project, then for purposes of 2023, do all of those projects -- are they then going to be considered in the baseline for any bids that would be received by the Company in 2023 solar procurements and beyond?

A. That's accurate. Once they're in the transmission plan or once they're assigned to a prior generator who has signed an interconnection agreement, then they would be in the baseline.

Q. Okay.

A. Did I say that correctly?

A. (Sammy Roberts) That's correct.

Q. So in the situation where -- and I know I'm in sort of a hypothetical.

But in a situation where they were not assigned to the generator, there is a possible situation where some red zone costs would flow through customers and some would be allocated directly to generators? For purposes of who pays the cost, to be clear about my use of the word "allocation?"

A. (Maura Farver) I think this is tricky because, ultimately, customers bay for it either way.

Q. I don't disagree with you.

A. The bid prices changing literally as a lever of that.

Q. Understood. I'm just talking about the mechanism where they could be flowing.

So we could see some transmission projects that ultimately make their way through base rates and others that make their way through increased PPA prices from third-party generators?

A. I think that is possible if these upgrades are, I guess, sort of, established piecemeal. I think that's right.

Q. And so in some --

CHAIR MITCHELL: All right. Ms. Grundmann, I'm gonna reel you in here some. We are -- this is not cross examination again. Recognizing that Commissioners have asked questions of the witnesses about the red zones and the panel, it's just not -- it wasn't carte blanche to ask any and all questions about it. So please remember to refer to a question that we -- a specific question that we've asked, and ask a follow-up on that question. We cannot go through cross examination of these witnesses on the general topic of the red zone and how those costs are going to be recovered or assigned or allocated or otherwise. So please limit your questions so that we finish this can hearing this week. Thank you.

MS. GRUNDMANN: Thank you, Chair

Mitchel. I apologize. I was trying to understand. I was somewhat confused. I think those are all the questions that I had.

MR. BURNS: I have -- can you hear?

EXAMINATION BY MR. BURNS:

Q. I have one question for you. In response to Commissioner Mitchell -- Chairwoman Mitchell's question, she was asking whether the Companies understood that by -- or anticipate, by the time the bid refresh window opened, there would be sufficient understanding of the IRA's tax credits.

Do you remember that line of questioning?

A. (Maura Farver) I recall that.

Q. In establishing the refresh window and dealing with the uncertainty that led to the refresh window, was the tax credit the only issue or was the tariff case also injecting some uncertainty into bids and understanding of the market? To your understanding.

A. I -- I think there was also a hope that there would be more information about the tariff case. And so having more assurance or indication of where that would land might allow bidders an opportunity to move their bids downward as well.

Q. Great. Thank you.

MS. CRESS: Chair Mitchell, I would ask that the Commission take judicial notice of Duke's T&D filing as required by Commission rules for a performance-based regulation rate case for Docket E-2, Sub 1300, which was filed August 3, 2022.

CHAIR MITCHELL: Did you identify the docket number?

MS. CRESS: I think I did, but let me do it again.

CHAIR MITCHELL: Okay.

MS. CRESS: Docket Number E-2, Sub 1300. The supplemental information Duke provided following the technical conference, which was filed on August 3, 2022.

CHAIR MITCHELL: Okay. There being no objection to your request, the Commission will take judicial notice.

MS. CRESS: Thank you.

EXAMINATION BY MS. CRESS:

Q. And following up on a couple -- and I'm not gonna reinvent the wheel here. But just following up on a couple of questions you got about cost recovery mechanism.

DEP has already identified RZEP upgrade projects as capital costs that it will seek to recover in its proposed multiyear rate plan in Docket Number E-2, Sub 1300, correct?

A. (Sammy Roberts) That's my understanding.

Q. And there are, would you agree, subject to check, 11 RZEP projects that Duke is going to seek cost recovery through its MYRP-4 in DEP?

A. Subject to check.

Q. And the cost of those projects' total, subject to check, would you agree, $212,345,684?

A. Subject to check, yes.

Q. How many of those -- this is going to Commissioner Hughes' question on benefits, and I believe also Chair Mitchell asked about maximizing benefits for ratepayers of the RZEP upgrades.

How many of those 11 projects have a cost benefit ratio less than one?

MS. KELLS: Objection. This is not the rate case, the PVR case. It's not relevant to what -- the Commissioners' questions.

MS. CRESS: To be fair, I did tie it to multiple different lines of questions from the Commissioners who asked about ensuring benefits to ratepayers from the RZEP upgrades.

CHAIR MITCHELL: I'll over -- I mean, I'm gonna sustain the objection.

Q. If the -- and sorry, let me back up. Last question, I believe. Tying this to multiple lines of questions that you got from Commissioners on what happens if the NCTPC votes to include the RZEP projects in the local transmission plan.

My question is, if the NCTPC votes not to include RZEP projects in the local transmission plan, will Duke still seek cost recovery through its upcoming multiyear rate plans?

A. So we'll still be seeking evaluation and approval of those RZEP projects through the NCTPC process, whatever new study evidence that would require. But, I mean, I think there's -- and intervenors have stated there's ample evidence through multiple studies that these projects are needed to execute the Carbon Plan.

Q. Was that a yes or a no to my question?

A. So your question, just to repeat, was what happens if the NCTPC does not --

Q. No. It was specifically will those costs still be sought for recovery through a multiyear rate plan if the NCTPC votes not to include these projects in the local transmission plan?

A. Yeah, I would leave that up to the termination of the rates people.

Q. Okay. Thank you.

CHAIR MITCHELL: Okay.

EXAMINATION BY MR. SNOWDEN:

Q. Mr. Roberts, I'm gonna start with the easy one. I'll try to move quickly here. This is following up on questions by Commissioner Hughes and Chair Mitchell about the information that was provided to developers regarding interconnection studies. Do you recall that?

A. Yes.

Q. Okay. And you testified that Duke provides the base cases used in interconnection studies to developers, and they can input those into Power -- PowerGEM; is that right?

A. My understanding is we provide the cases associated with the studies performed for the DISIS, and that the person that retrieves those cases would need to have the PowerGEM application called TARA, T-A-R-A, to be able to utilize those cases to reproduce results.

Q. Okay. So when Duke does a -- an interconnection study, it takes cases -- it takes a baseline and then it studies that baseline under various scenarios and contingencies, right -- I'm sorry, contingencies, correct?

A. That's correct. We look at -- and we provide that file as well, the contingency -- contingency-monitored element file.

Q. So it's your position that Duke informs developers of exactly what contingencies and scenarios that it is studying in the interconnection process?

A. Subject to check, my understanding is that information in a file is provided.

Q. Okay. Would you agree that, when Duke identifies an overload in an interconnection study, it does not tell developers what the magnitude of that overload is or what the contingencies or scenarios that triggered it are?

A. So the person utilizing those files and using the PowerGEM tool TARA would need to have some knowledge of how to generate the DFAX file from TARA to be able to assess which elements are overloaded. And the line loading percentage, the check and see if the loading percentage was over 1 percent, that's just using the power play numbers.

Q. Okay. But Duke does not provide that information directly to developers; is that right?

A. Well, the results would be provided in the transition cluster study, or the DISIS study results.

A. (Maura Farver) I was gonna say, the phase 1 report, I think, has the DFAX contribution of the generators.

Q. Understood. But the DFAX contribution is, sort of, the end result of a fairly complex analysis, isn't it?

A. (Sammy Roberts) It's the result of utilizing those cases that are posted once the study is completed.

Q. Okay. Thank you. So Chair Mitchell and Commissioner Hughes, Commissioner Kemerait asked a number of questions about the timing of the RFP relative to the red zone upgrades.

So just to clarify, Duke's proposal is that the red zone upgrades would go into the local transmission plan around January of 2023 if they are approved by the TPC; is that right?

A. That's about the time the final report would be posted with the red zone projects included if they were included in the local transmission plan.

Q. And bid evaluation for the RFP -- the 2022 RFP happens when?

A. (Maura Farver) The step 2 bid evaluation?

Q. Yes, the step 2 bid evaluation.

A. So we'll essentially begin the end of December, and use updated information in April, and use information from the DISIS phase 2, which we hope to receive in early May. I think that was the answer.

Q. Thank you. So by the time you do the step 2 evaluation, you will know whether the RZEP are in the local transmission plan, correct?

A. I think so. I'm not sure how the timing of whether RZEP is in the transmission plan makes its way into the phase 2 process. Since phase 2 will already be underway in December, I'm not sure about the timing of how those two pieces merge.

Q. Understood. But when you do the bid evaluation process, you will at least know by that point whether the RZEP are or are not in the local transmission plan?

A. I believe so.

Q. And you testified that Duke's plan, as of now, is to factor in the full cost allocation of any red zone upgrades into the bid evaluation process for the 2022 RFP, correct?

A. That's correct.

Q. And you testified that this was driven by the Commission's order in the RFP docket that the RZEP not be included in the baseline for the 2022 DISIS, correct?

A. That's correct.

Q. And -- but as I believe Chair Mitchell noted, that bid evaluation is not the same as the allocation of costs in interconnection studies; would you agree with that?

A. That was what I took her to mean, yes.

Q. Okay. And in its order in the RFP docket, the Commission did not tell Duke how it should go about doing bid evaluations for the 2022 RFP, correct?

A. I don't think that level of detail was covered.

Q. Okay. And as I read the RFP, it lays out the multipart bid structure that you described, but does not specify, in detail, how Duke is going to be considering upgrade costs in a bid evaluation.

Do you agree with that?

A. Subject to check.

Q. Thank you. So Duke's current plan for bid evaluation is what you worked out with -- with CRA at present; is that correct?

A. That's correct.

MR. SNOWDEN: Okay. Chair Mitchell, I would ask that the Commission take judicial notice of the June 17, 2022, compliance filing by Duke in Docket Numbers E-2, Sub 1297 and E-7, Sub 1268. That's the RFP.

CHAIR MITCHELL: All right. Having heard no objection, the Commission will take judicial notice.

MR. SNOWDEN: Thank you.

Q. Ms. Farver, in the RFP, or with the RFP, Duke provided locational guidance to bidders, correct?

A. That's correct.

Q. Okay. And if I may -- and that locational guidance indicated that the red zone up- -- red zone areas were constrained, right?

A. That's correct.

Q. But in the RFP -- and I apologize I don't have a copy of it to review -- but would you agree that in the RFP, Duke said, in essence, the red zone is constrained, however, we have -- we are proposing upgrades to the TPC and so the situation may change?

MS. KELLS: I'd just like to ask the Chair to ask counsel how much longer this is going. It seems a little bit --

MR. SNOWDEN: I do not have very much more. I am -- and I am following directly on Chair Mitchell and Commissioner Hughes and Commissioner Kemerait's questions about how the red zone upgrade evaluation fits in with the RFP evaluation. So I do not have a set of lines, I'm simply trying to clarify where we stand with regard to red zone upgrades in bid evaluation for the RFP.

CHAIR MITCHELL: All right. As long as your questions are following up on questions that we asked and not continuing down --

MR. SNOWDEN: Yes, ma'am. I'm not going down any alleys, I assure you.

CHAIR MITCHELL: All right. Go ahead.

THE WITNESS: Subject to check, I think our final version of the RFP document did not have that statement, because I believe we edited it after the Commission said to not include the RZEP in the baseline.

Q. Okay.

A. So I'd want to check the final filed version.

Q. Okay. Understood. Thank you. So back to the bid evaluation process.

If Duke were to, for example, come up with a different way to evaluate the cost impact of upgrades, or the red zone upgrades specifically in the RFP, you would not be upsetting any settled expectations of bidders, would you?

MS. KELLS: Objection.

CHAIR MITCHELL: Yeah, sustained.

Q. Thank you. Okay. We have been talking a lot about, and the Commissioners have asked a number of questions about how the red zone upgrades could be considered in bid evaluation.

Is the question of how those upgrades could be considered in bid evaluation appropriate for consideration in the RFP docket?

A. I think it's appropriate for discussion for a 2023 RFP. I'm not sure that it's appropriate to change the evaluation process mid-flight in the current 2022 RFP. So I think it makes sense to discuss this in planning the '23 RFP.

Q. But, Ms. Farver, you did just testify that the RFP does not really specify in detail how --

MS. KELLS: Objection. We're just way far beyond and wading deep into areas beyond Commissioner questions and this proceeding's purpose.

MR. SNOWDEN: I have two more questions, and I believe I'm squarely within the scope of a number of questions that Commissioners have asked on this question of how the red zone upgrade fits in with the bid evaluation.

CHAIR MITCHELL: All right.

MR. SNOWDEN: I understand I have a short leash, and I have three questions left.

CHAIR MITCHELL: All right. Every time that we must -- well, every time that there is an objection and there is a response and then I have to rule on objection also takes the Commission's time as well. So I'm gonna just ask you-all one more time, all sides, please do your best to -- please, you-all are capable of limiting your questions to questions that the Commissioners have asked.

I asked you all yesterday to identify the question, the specific question verbatim that you were responding to. I've given you some leeway in not requiring that you do that today. But for the sake of regulatory economy, we've got to get through this proceeding. And I ask you all to use your best judgment in helping us get there, and stop straying beyond Commissioner's questions. All right. With that, ask your final two questions and then let's move on.

MR. SNOWDEN: Thank you.

Q. Ms. Farver, Commissioner Hughes asked if there was a danger -- I believe it was Commissioner Hughes asked if there was a danger that if the -- depending on how bid evaluations were done in the 2022 RFP, Duke might end up picking a set of projects that are not least cost; do you recall that?

A. I recall.

Q. Okay. And it's Duke's plan, if the red zone upgrades are approved by the TPC, to designate those as contingent facilities, in which case the costs will not be allocated to individual projects; is that correct?

A. I'm sorry, say that again.

Q. I'm trying to be very quick. It's Duke's -- you testified that it's Duke's plan to designate the red zone upgrades as contingent facilities if they're approved by the TPC; is that correct?

A. In the ultimate interconnection agreement, they, I believe, would become contingent facilities if they're approved in a local transmission plan before that time.

Q. Thank you. And in that case, the actual project would not bear the cost of those upgrades, correct?

A. The generator, in that instance, would not pay the host of the contingent facilities.

Q. Thank you. So last question.

MS. KELLS: No, that's four questions.

Q. Would you agree that there is a danger that if bid selections in 2022 reflect the full phase 2 cost of the red zone upgrades, you could end up picking projects that are not actually lowest cost to ratepayers?

A. I think that we are operating the 2022 RFP under the best information we had at the time that the RFP was designed, and so we should stick with the rules and design of the RFP as it was announced to all bidders to remain fair. But this can be a consideration for future RFP cycles where the rules and specifics have not yet been determined.

Q. Thank you, Ms. Farver.

MR. SNOWDEN: Thank you, Chair Mitchell, for your patience. I have no more questions.

CHAIR MITCHELL: All right. We're gonna recess. We'll come back on the record at 3:20. Let's go back on the record.

(At this time, a recess was taken from 2:56 p.m. to 3:22 p.m.)

CHAIR MITCHELL: Let's go back on the record. We'll continue with questions on Commissioners' questions. Who's up? Any additional questions on Commissioners' questions?

MR. JOSEY: No.

CHAIR MITCHELL: Okay.

MS. KELLS: No questions.

CHAIR MITCHELL: All right. I actually have one last question, and then I'll let you-all go.

EXAMINATION BY CHAIR MITCHELL:

Q. The -- and this is for you, Mr. Roberts. Affected system costs.

Any affected system costs that would result from red zone projects, how would those be accounted for in the -- either in the NCTPC process or just in general?

A. (Sammy Roberts) So I'll just describe what I know about affected systems and how those costs are allocated or how they're paid. My understanding is that, for example, if a solar facility locating in Duke Energy Carolinas created an affected system in Dominion Energy South Carolina, then -- and that was revealed through study that that was actually the case, we have a means for, in our study, if we see a certain level DFAX associated with that solar on a neighboring facility, we'll notify the neighboring facility.

If that -- if a study is performed and they say, yeah, we have an affected system, the generator pays for the affected system upgrade, and then the -- Dominion Energy South Carolina would reimburse the generator that amount paid for that upgrade and they would collect it through their rates.

A. (Maura Farver) But I think that just from executing the red zone upgrades by themselves, doing those network upgrades I don't think causes an affected system upgrade.

A. (Sammy Roberts) Correct.

Q. Okay. Thank you for that follow-up. That was really my question, is typically we do see -- I mean, I understand that affected system issues would arise in the context of a generator interconnection request. And Mr. Ragsdale testified as to that when here, and so my curiosity was would the actual red zone cause any affected system cost, but you've answered.

A. (Maura Farver) Yeah, my understanding is no. By upgrading our transmission system, it's not having a negative impact. That's my understanding.

Q. So affected -- so any affected system costs coming out of the red zone would be driven by generators that are actually interconnecting on red zone projects?

A. (Sammy Roberts) Right. I believe what Mr. Ragsdale was referring to is short-circuit availability to their PODs. And every two years our protection and controls engineering group provides the available short-circuit to their EMC PODs. And then also, our transmission planners, when they evaluate a generator interconnection, if they see that that short-circuit could potentially elevate that EMC POD availability, they will notify EMC.

Q. Okay. And so then what would happen?

A. So if, for example, their breaker KA, kiloamperes, rating was too low, then that breaker would need to be replaced. And to be honest with you,

I'm not sure how that cost is allocated.
Q. Okay. You anticipated my question. Mr. -- I understood Mr. Ragsdale's testimony to be that the cost causer would be responsible for that cost.
And so my question is -- or my concern is, if the red zone projects impact the points of delivery -- I'm assuming POD is points of delivery?
A. That's correct.
Q. Okay. That then the Duke utility would be responsible, and ultimately Duke's customers would be responsible for work that's necessitated to fix -- to correct the problem on the point of delivery?
A. Okay. And I would say with more IVRs and retiring more synchronous generation, you're gonna have less fault current, not more. And so that's -- I won't say all, but over time, most of their PODs should see less short-circuit availability to their PODs.
Q. Okay. So what I'm understanding your testimony to be is that, given the nature of the changes, are the -- the projects you anticipate, the red zone projects, there could be fewer issues than anticipated by the EMCs or --
A. That or definitely not exacerbated.
Q. Okay. Okay.

CHAIR MITCHELL: Did you want to -- okay. All right. With that, you-all -- we appreciate very much your testimony today. You-all may step down and be excused. And thank you for your participation in this proceeding. We will take motions.

MS. KELLS: At this time, I move that the panel's three exhibits be admitted into the record.

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

(Transmission and Solar Procurement Panel Rebuttal Exhibits 1 through 3 were admitted into evidence.)

MR. SNOWDEN: Chair Mitchell, I would move that CPSA Transmission Panel Rebuttal Cross Examination Exhibit 1 be moved into the record.

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

(CPSA Transmission Panel Rebuttal Cross Examination Exhibit 1 was admitted into evidence.)

CHAIR MITCHELL: All right. Duke, you may call your next witnesses.

MS. LINK: Duke Energy recalls the Long Lead-Time Resources Panel. And, Chair Mitchell, while the panel is coming up to the stand, just two administrative items. There -- we had just made the filing of revised version of the testimony to omit references to TotalEnergies' testimony because that was withdrawn from the proceeding. So that is now in the docket. I believe you-all have copies and we have shared copies for folks in the room.

The other item that was carryover from the direct testimony was how we would manage to go into confidential session at the appropriate time upon questions by the parties or the Commission, and we have worked that out with Avangrid's counsel as to mechanism that would occur. It would be conducted under the standard confidentiality agreement that the parties have filed here, and at the right time we're able to go into confidential session as needed.

CHAIR MITCHELL: Okay. So I understand you to mean that you all have come to an agreement on discussion -- the discussion of confidential information in this hearing room?

MS. LINK: Yes, Chair Mitchell, we have.

CHAIR MITCHELL: Okay. And so if we have to go into confidential session, we'll do as we normally do, cut off the -- we'll clear the room and we will discontinue the stream.

MS. LINK: Thank you, Chair Mitchell.

CHAIR MITCHELL: Okay. All right. Gentlemen, let's get you sworn in.

Whereupon,

REGIS REPKO, CHRIS NOLAN, AND CLIFT POMPEE,
having first been duly sworn, were examined
and testified as follows:

CHAIR MITCHELL: Did we lose one of you?

THE WITNESS: (Regis Repko) Mr. Immel is not appearing.

CHAIR MITCHELL: All right. Mr. Immel is the lucky one, huh?

DIRECT EXAMINATION BY MS. LINK:

Q. Mr. Repko, with the exception of Mr. Immel, are you the same Long Lead-Time Resources Panel that appeared on this proceeding September 20, 2022, as part of the Companies' direct case?

A. (Regis Repko) Yes.

Q. And did the panel cause to be prefiled in this docket rebuttal testimony that now has been amended as of September 28, 2022, that consists of 26 pages?

A. Yes.

Q. And those changes -- with those changes or corrections that have been made today, would -- if I were to ask you the -- do you have any additional changes or corrections, sir?

A. Yes, we have --

Q. Mr. Repko, excuse me, the corrections that we just made, are there any additional changes or corrections?

A. Oh, no.

Q. And if I were to ask you those questions appearing today, would you provide the same answers here today?

A. Yes.

Q. And do -- has there also been a summary prepared of the panel's rebuttal testimony?

A. Yes.

MS. LINK: Chair Mitchell, we ask that the Long Lead Resources Panel corrected rebuttal testimony that was filed today, and summary, be entered into the record as if given orally from the stand.

CHAIR MITCHELL: All right. Motion is allowed.

(Whereupon, the prefiled rebuttal testimony of Regis Repko, Chris Nolan, and Clift Pompee and the prefiled summary testimony of Regis Repko, Chris Nolan, and Clift Pompee 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	)	**REGIS REPKO, CHRIS NOLAN**
Duke Energy Carolinas, LLC, 2022	)	**AND CLIFT POMPEE ON**
Biennial Integrated Resource Plan	)	**BEHALF OF DUKE ENERGY**
And Carbon Plan	)	**CAROLINAS, LLC AND DUKE**
	)	**ENERGY PROGRESS, LLC**

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

A. My name is Regis Repko. My business address is 526 South Church Street, Charlotte, North Carolina, 28202. I am Senior Vice President of Generation and Transmission Strategy for Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP") and together with DEC, the "Companies" or "Duke Energy"). I have one correction from my direct testimony. My career began with Duke Energy in 1985 as an engineer at the Oconee Nuclear Station. I am providing rebuttal testimony today on behalf of the Companies with Chris Nolan and Clift Pompee on Long Lead-Time Resources.

Q. PLEASE IDENTIFY WHICH WITNESS SPONSORS EACH SECTION OF YOUR REBUTTAL TESTIMONY.

A. Mr. Repko sponsors Section I (Overview) and IV (Conclusion); Mr. Nolan sponsors Section II (New Nuclear); and Mr. Pompee sponsors Section III (Offshore Wind). From our review of the intervenor and Public Staff testimony, there appears to be substantial support for Bad Creek II and recognition of its need and no material opposition; therefore, the Companies are not providing rebuttal testimony regarding Bad Creek II.

Q. WHAT IS THE PURPOSE OF THE LONG LEAD-TIME RESOURCES PANEL'S REBUTTAL TESTIMONY?

A. The purpose of the Long Lead-Time Resources Panel's rebuttal testimony is to reaffirm the Companies' request for relief regarding the near-term development activities and related costs for the three long lead-time resources. This Panel's rebuttal testimony also responds to certain comments, critiques, and recommendations offered in the Direct Testimonies of Dustin Metz and Michelle Boswell on behalf of the Public Staff; Edward Burgess on behalf of the Attorney General's Office ("AGO"); Nicholas Prokopuk on behalf of TotalEnergies Renewables USA, LLC ("TotalEnergies"); Dr. Michael Starrett and Becky Gallagher on behalf of Avangrid Renewables, LLC ("Avangrid"); Michael P. Gorman on behalf of CIGFUR II & III ("CIGFUR"); and Dr. Arjun Makhijani on behalf of the Environmental Working Group ("EWG").

Q. MR. REPKO, PLEASE SUMMARIZE THE KEY TAKEAWAYS OF YOUR JOINT REBUTTAL TESTIMONY FOR THE COMMISSION.

A. The Companies continue to believe that it is reasonable and prudent to invest in the development of the three long lead-time resources (i.e., Bad Creek II, New Nuclear through small modular reactors ("SMRs"), and Offshore Wind) to meet the ambitious carbon reduction goals established by North Carolina Session Law 2021-165 ("HB 951"). While there appears to be a general consensus that developing Bad Creek II is a necessary step towards meeting the carbon reduction goals set forth by HB 951, there is less agreement on the Companies' pursuit of the development of offshore wind and new nuclear generating sources. But the Companies' position is clear—all three long lead-time resources will be needed to generate the significant amount of carbon-free energy needed to meet the targets set forth by HB 951.

The Companies' request is not changed by the positions set forth in the direct testimonies of intervenors and the Public Staff. In sum, the Companies are asking the Commission to approve the decision to pursue near-term development activities and incur costs related to the three long lead-time resources. The Companies are not asking the Commission to select one of the long lead-time resources for inclusion in the Carbon Plan at this time. Rather, the Commission's approval of this request will, in part, allow Duke Energy to further analyze these long lead-time resources so that it can pursue initial work through activities like a Pre-Feasibility/Feasibility Study for Bad Creek II, Early Site Permit ("ESP") for SMRs and a Site Assessment Plan ("SAP") for offshore wind. These initial efforts are beneficial in that once permits are completed, they retain value for use in the future and also preserve the potential to be able to use one or more of these resources to meet the 70% interim carbon emissions reduction target ("70% Interim Target") of the Carbon Plan. In addition, these efforts will also provide the Company further information in terms of costs and timelines to be able to assess when to bring these resources in a cost-effective manner to the Commission in a future Carbon Plan proceeding for selection.

The Companies intend to pursue these development activities and incur costs in a reasonable and prudent manner and, as is further explained below, propose to implement cost caps for the development activities. This issue is also addressed in the Companies' Comments filed on September 9, 2022 ("Comments").

This testimony also rebuts the EWG's comments and criticisms related to the Companies' proposed development of new nuclear generating sources. The EWG's comments incorrectly allege that new nuclear technologies will suffer from the same issues—like high costs and long construction timelines—that were inherent to older nuclear technologies. The EWG's comments, however, ignore three key points about the new nuclear technologies: First, the technology that is used in these new reactor designs has evolved from the plant designs of the 2000s. Second, the modular design of these new nuclear reactors will allow for more off-site construction, which will decrease production timelines. Third, the designs of these new reactors will require less capital investment because both SMRs and advanced reactors ("AR") are smaller than traditional reactors. In sum, the EWG's comments mistakenly attempt to use the issues that faced the reactor designs of the 2000s to prejudice new nuclear technologies.

Lastly, while the Companies remain open to opportunities for ownership of cost-effective offshore wind energy areas ("WEA") to develop on behalf of our customers that were introduced by certain parties in this proceeding, we have concerns with the arrangements discussed by these parties for two primary reasons. First, these parties appear to continue to contemplate, at least in part, arrangements that do not meet the ownership requirements of HB 951. Second, procuring a WEA from these parties carries timing, cost, and certainty risk in contrast with the development option that is most readily and directly available to the Companies.

Therefore, the Companies believe the best and most certain path is to acquire the Carolina Long Bay WEA from their affiliate Duke Energy Renewables Wind, LLC ("DERW"). The Companies would make the appropriate affiliate filing pursuant to the requirements of Gen. Stat. § 62-153 in a separate proceeding in early 2023, and Commission approval of the decision to acquire the lease in this proceeding would be effectuated in that separate proceeding. This path forward has four primary benefits. First, it is simple and straightforward. Second, this path has certainty of timing because the Companies know DERW is willing to sell the lease in a timely and efficient manner at cost, which will preserve the potential for offshore wind to be available on a timeline consistent with the Companies' modeling. Third, this path clearly meets the utility ownership requirements of HB 951. Fourth, this path does not foreclose other options but does ensure that at least one offshore wind project is available for further consideration in the 2024 Carbon Plan update.

I will note that the Companies have filed, in parallel with our testimony, Comments addressing certain legal issues that are relevant to my testimony. While I am not an attorney and am not testifying with respect to such legal issues, those Comments, among addressing other issues, set forth the Companies' view that the (1) HB 951's ownership requirements are clear and unambiguous, and (2) that the Commission has the authority to and should, in fact, grant the Companies' requested relief with respect to the development activities for these long lead-time resources.

I. OVERVIEW

Q. MR. REPKO, PLEASE RESPOND TO PUBLIC STAFF'S RECOMMENDATION THAT THE COMMISSION DENY THE COMPANIES' REQUEST FOR APPROVAL OF DEVELOPMENT ACTIVITIES TO FURTHER AN OFFSHORE WIND PROJECT.

A. The Public Staff's position, if adopted by the Commission, would effectively eliminate the ability to keep offshore wind as an option to meet the 70% Interim Target of the Carbon Plan. The Companies do not believe this is a prudent approach, as it is inconsistent with the "all of the above" strategy addressed at length in the Companies' Carbon Plan. As I stated in my direct testimony, the Companies believe that it is likely that offshore wind will be needed to meet the ambitious carbon reduction goals of HB 951, and, therefore, it is prudent and reasonable to engage in development activities in the near-term to pursue initial development and permitting requirements and refine cost estimates. Avangrid,[1] TotalEnergies,[2] and the AGO[3] are aligned with the direction that the Companies should pursue

[1] Avangrid Gallagher Direct Testimony at 12.
[2] TotalEnergies Prokopuk Direct Testimony at 9.
[3] AGO Burgess Direct Testimony at 75.

development activities to further offshore wind and retain the ability to meet the 70% Interim Target.

Q. THE PUBLIC STAFF[4] WOULD LIKE THE COMMISSION TO MAKE CLEAR THAT APPROVAL OF THE LONG LEAD-TIME RESOURCE DEVELOPMENT ACTIVITIES THROUGH THE COURSE OF THE CARBON PLAN PROCEEDING SHOULD NOT OBVIATE THE NEED FOR A FUTURE CPCN PROCEEDING. CAN YOU COMMENT?

A. Yes. The Companies have been clear that its request in this proceeding involves only the approval to proceed with development activities and incur costs related to the three long lead-time resources (*i.e.*, Bad Creek II, New Nuclear through SMRs, and Offshore Wind) and is not a request that the Commission select such resources for purposes of the Carbon Plan. Furthermore, the Commission's approval of development activities would have no impact on any future required regulatory approvals for such projects, including, where applicable, a CPCN. In addition, the Companies recognize that in future base rate proceedings, they bear the burden of proof to show that the costs for the expenditures themselves were reasonable and prudent.

[4] Public Staff Metz Direct Testimony at 18; Public Staff Thomas Testimony at 45, 70.

Q. SETTING ASIDE THE LEGAL ISSUES ADDRESSED IN THE COMPANIES' COMMENTS, PLEASE REITERATE WHY THE COMPANIES ARE REQUESTING COMMISSION APPROVAL OF THESE DEVELOPMENT ACTIVITIES.

A. Because these resources are unique relative to other resources due to the longer development and construction timelines and the total development costs required to be incurred prior to approval of construction, the Companies need assurance from the Commission through this proceeding that development of these resources and the associated costs of the development activities are reasonable and prudent and appropriate for cost recovery. Without the requested assurances, the Companies may elect to continue some development work, but it will not allow these resources to be available on a timeline necessary to achieve the 70% Interim Target—and to achieve the 70% Interim Target, Bad Creek II and either SMRs or offshore wind are needed. Said another way, the Companies are seeking to create and retain options through "no regrets" activities like the ESP, lease acquisition and SAP that will be able to be used during the course of the Carbon Plan, but also to allow further development to be able to make prudent selections of these resources in future Carbon Plans.

Q. THE PUBLIC STAFF ALSO STATES THAT THESE PROJECTS ARE NOT OUTSIDE THE NORMAL COURSE OF BUSINESS FOR THE COMPANIES.[5] PLEASE RESPOND.

A. The Companies respectfully disagree with Public Staff's opinion that incurring development costs of this magnitude without Commission pre-approval is in the "normal course of business." The Companies are not aware of any other instance in which the Companies were required to incur hundreds of millions of dollars to develop a yet-to-be-approved asset for purposes of compliance with a law without any pre-approval. As discussed above, these three resources are unique based on (1) the scale of the costs required to be incurred prior to construction approval, (2) the length of time for their development, and (3) the timing required to potentially make them available as a solution to meet the 70% Interim Target of the Carbon Plan. The Companies discuss this issue further in their Comments.

[5] Public Staff Boswell Direct Testimony at 6.

Q. BOTH AVANGRID AND TOTALENERGIES URGE THE COMMISSION TO MAKE SPECIFIC FINDINGS REGARDING INCLUSION OF OFFSHORE WIND IN THE CARBON PLAN AND ISSUANCE OF A MANDATE FOR OFFSHORE WIND DEVELOPMENT. DOES THE COMPANY BELIEVE THESE FINDINGS ARE NECESSARY?

A. No, the specific findings requested are not based on modeling results and are, therefore, unsupported and premature. Avangrid requests three forms of relief: (i) inclusion of offshore wind in the final Carbon Plan; (ii) a formal process through an independent third-party consultant study to compare and prioritize regional offshore wind resources based on cost, efficiency, viability, and schedule ("Third-Party Wind Energy Area Comparison Process"); and (iii) direction to the Companies to take all reasonable steps to procure offshore wind.[6] Likewise, TotalEnergies urges a "mandate" in the Carbon Plan to develop a portfolio of 2-4 GW of offshore wind.[7] It is not necessary to grant any of these requests at this time.

First, the Companies are not asking for offshore wind to be selected in the Carbon Plan at this time, and Avangrid provides no material independent support for the selection of offshore wind at this time. Without further information that will be gained by pursuing the development activities and modeling results based on that information, the selection of

[6] Avangrid Gallagher Direct Testimony at 24.
[7] TotalEnergies Prokopuk Direct Testimony at 6.

offshore wind now would be premature. Likewise, the Carbon Plan itself is not a vehicle for a “mandate” for any particular resource. The Carbon Plan is a disciplined process to assess the least-cost path to achieve CO_2 reductions, and the Commission is tasked with selecting resources that are shown to be part of the least-cost path. There is nothing in HB 951 that suggests the Commission should issue a generic mandate for any particular resource.

Second, the Companies do not believe that hiring an independent third-party consultant to run a Third-Party WEA Comparison Process is necessary. I discuss below the Companies’ plan to acquire the WEA owned by DERW. Therefore, there is no need to compare multiple WEAs and projects at this time.

Q. BOTH AVANGRID[8] AND TOTALENERGIES[9] HAVE NOW STATED IN TESTIMONY A POTENTIAL INTEREST IN SELLING THEIR RESPECTIVE PROJECTS TO THE COMPANIES. PLEASE COMMENT ON THIS TESTIMONY.

A. While the Companies remain open to opportunities for ownership of cost-effective offshore wind WEAs to develop on behalf of our customers, we have concerns with the arrangements discussed by these parties for several reasons. First, the parties still discuss arrangements, such as power purchase agreements, that do not meet the ownership requirements of HB 951, for the

[8] Avangrid Gallagher Direct Testimony at 14.
[9] TotalEnergies Prokopuk Direct Testimony at 8.

reasons explained in the Comments. Second, procuring a WEA from a non-affiliate third party carries timing, cost, and certainty risk. If the Companies are to develop offshore wind to be available to meet the 70% Interim Target, decisive and certain action needs to be taken now. A competitive procurement for the WEA could take years. There is simply not time to delay the pursuit of an ownership interest in a WEA to meet the 70% Interim Target and pursue development activities should the Commission agree with the Company's request in this proceeding.

Q. HOW DO THE COMPANIES INTEND TO PROCEED TO ACQUIRE AN OWNERSHIP INTEREST IN A WEA?

A. The Companies believe the best and most certain path is to acquire the Carolina Long Bay WEA from their affiliate DERW. DERW participated in the last BOEM auction held in May 2022, before a 10-year leasing moratorium, which ensured that a WEA that could be owned by the Companies is available for development. Acquiring this lease in the near-term, as recommended by the Companies, would give the Commission and the Companies substantially more discretion and control over the pace and timing of development. Importantly, this includes establishing a clear pathway to ensure that the Commission will have the ability to further consider an offshore wind resource in the 2024 Carbon Plan update that clearly complies with the utility ownership requirements of HB 951. This option puts the Companies and the Commission in the decision-making control for considering offshore wind, while not foreclosing the potential for other cost-effective projects as discussed further below. The Companies would seek acceptance of the affiliate agreement from the Commission in a separate proceeding in early 2023, post Commission approval in this proceeding, to transfer the Carolina Long Bay lease from DERW to the Companies at the price that DERW paid for the WEA (approximately $155 million). Commission approval of the decision to acquire the lease in this proceeding would be effectuated by the Commission through acceptance of the affiliate agreement in this separate proceeding. After such transfer, the Companies would proceed with development activities on the Carolina Long Bay lease to further the opportunity to develop an offshore wind project to meet the 70% Interim Target.

This path forward has four primary benefits. First, it is simple and straightforward. Based on affiliates' restrictions, the Company must procure the WEA at the lower of cost or market. The BOEM auction was an independent, third-party process that set the market price in May 2022, at approximately $155 million. This is also the DERW cost for the WEA. Therefore, the price for the WEA does not have to be negotiated and is certain. Second, this path has certainty of timing because the Companies know DERW is willing to sell the lease, and it will be subject to a straightforward affiliates' agreement application before the Commission. Third, this path clearly meets the utility ownership requirements of HB 951 and therefore would not be subject to complex negotiations and structures that arguably would not comply with the statute. Fourth, this path does not foreclose other options but does ensure that at least one offshore wind project is available for further consideration in the 2024 Carbon Plan update.

Q. DOES THIS MEAN THAT THE AVANGRID'S AND TOTALENERGIES' PROJECTS WILL NEVER PLAY A ROLE IN THE CARBON PLAN?

A. No, absolutely not. The Companies remain open to potential commercial arrangements that are consistent with HB 951's ownership requirements and cost-effective for the Companies' customers. If such opportunities are identified in the future, the Companies will pursue them and, if appropriate, will present them to the Commission for consideration.

Q. DO THE COMPANIES BELIEVE THAT IT IS REASONABLE TO IMPOSE A CAP ON THE DEVELOPMENT COSTS TO BE INCURRED BY THE COMPANIES FOR THESE RESOURCES?

A. Yes, the Companies believe that it is reasonable for the Companies' development costs to be capped at the amounts in Rebuttal Table 1 (which shall not be exceeded without Commission approval). Note, these amounts have been rounded from Tables 1, 2 and 3 from this panel's direct testimony for purposes of establishing cost caps:

Rebuttal Table 1

Long Lead-Time Resource	Proposed Development Cost Cap (2022-2024)
Offshore Wind	$325 million[10]
Nuclear	$75 million[11]
Bad Creek II	$40 million

Q. HOW WOULD THE COMPANIES KEEP THE COMMISSION APPRISED OF THE STATUS AND MILESTONES ASSOCIATED WITH THE DEVELOPMENT ACTIVITIES?

A. The Companies commit to provide a biannual update to the Commission and provide a summary of all major development activities (including costs incurred) and milestones.

Q. CIGFUR RECOMMENDS THE COMMISSION CONSIDER A PERFORMANCE GUARANTEE FOR OFFSHORE WIND LIKE THAT ORDERED BY THE VIRGINIA STATE CORPORATION COMMISSION ("VSCC") FOR DOMINION ENERGY'S CVOW PROJECT.[12] HOW DO YOU RESPOND TO THIS SUGGESTION?

A. Any imposition of a performance guarantee is premature and would adversely prejudge the future resource without any supporting facts. This is not a proceeding where offshore wind is being selected as the Companies are requesting that the Commission approve the decision to begin

[10] Includes estimated cost of obtaining an offshore wind lease.

[11] Costs associated with development work needed to obtain an Early Site Permit for a single site.

[12] CIGFUR Muller Direct Testimony at 12.

development and incur associated costs for these long lead-time resources. Moreover, the performance guarantee that CIGFUR witness Muller suggests be adopted has been suspended pending the outcome of the VSCC's pending reconsideration of its CVOW Order.

II. NEW NUCLEAR

Q. CAN YOU EXPLAIN HOW PURSUIT OF SMRs AND ARs DIFFERS FROM THE 2000s, WHICH THE EWG REFERS TO AS THE "NUCLEAR RENAISSANCE?"[13]

A. SMRs and ARs are distinctly different than the large light-water-cooled nuclear plants (i.e., Generation III/III+) that were planned to be built during the early 2000s. The next generation SMRs and ARs have significant advantages over their historical counterparts. The modular design of these new reactors allows for more off-site construction and decreases production and construction timelines. Designs have become smaller, meaning units require less capital investment and are more flexible, allowing for greater ability to match power output to system loads. In addition, the new generation of nuclear plants have significant safety enhancements. Inherent safety features, such as passive shut down and self-cooling through natural circulation, mean that the system can turn off and cool itself with no operator intervention. This enhanced safety makes the plants less complicated (i.e., fewer systems needed), enabling easier construction and

[13] EWG Makhijani Direct Testimony at 6-9.

operation. The ability to build these next generation advanced nuclear plants much quicker and with less financial risk, while providing always-on baseload power generation, will help enable the Companies transition to net-zero carbon emissions.

Q. THE EWG CLAIMS THAT NONE OF THE REACTOR DESIGNS INCLUDED IN TABLE L-5 IN APPENDIX L OF THE CARBON PLAN HAVE BEEN CERTIFIED.[14] IS THAT A SUFFICIENT REASON TO PREVENT THE COMPANIES FROM PURSUING THE DEVELOPMENT ACTIVITIES?

A. No. The focus at this time is to pursue siting for an SMR by developing an Early Site Permit ("ESP"). Obtaining an ESP allows the NRC to review and approve the environmental impacts and site safety analysis associated with nuclear deployment at a particular site before a technology needs to be selected or a decision to build has been made. This allows time for the reactor technologies to develop, providing Duke Energy more time to make a better-informed decision on the best technology, or technologies, to pursue. An ESP is approved for up to 20 years and can be renewed. Simply put, the ESP has value that is retained for a long period of time which allows time for the technologies to mature.

To date, the only advanced nuclear reactor technology to receive an approved design certification from the NRC is the NuScale VOYGR plant.

[14] EWG Makhijani Direct Testimony at 21.

The other leading designs are in various stages of the pre-license application process with the NRC.

Q. THE EWG STATES THAT ARs WILL GENERATE NEW WASTE TYPES THAT MAY POSE ISSUES.[15] PLEASE RESPOND.

A. The light-water-cooled SMRs like the NuScale VOYGR and the GEH BWRX-300 use fuel of similar design, enrichment, and burnup as compared to the large light-water-cooled nuclear plants that we currently operate. It is reasonable to expect that the waste from these reactors would be handled similarly to our current practices. We see no reason to expect any appreciable differences. Our existing nuclear plants have stored used fuel onsite for years with the ability to store it there for the life of the plant. This experience demonstrates the ability to safely store used fuel onsite for new reactors until a federal repository is made available.

Q. THE EWG CLAIMS THAT THE COMPANIES' NUCLEAR CAPITAL COST SENSITIVITY ANALYSIS DOES NOT REFLECT HISTORICAL OR RECENT COST ESCALATIONS.[16] PLEASE RESPOND.

A. Historic or recent cost escalations in the most recent nuclear plant projects (e.g., Vogtle Units 3 & 4) are not valid comparisons because of the differences in characteristics of SMRs and ARs. The reactor technologies are too dissimilar to compare projects building two Generation III+ large

[15] *Id*. at 33-35.
[16] EWG Makhijani Direct Testimony at 11-12.

light-water-cooled reactors (i.e., total of approximately 2,200 MW) with the smaller, modular and less complex reactor designs (i.e., typically 50-350 MW). To date, there have been no new nuclear SMR or AR plants built, though there are four projects that are scheduled to be completed before the end of this decade. Duke Energy will closely monitor these first-of-a-kind reactor projects to obtain the refined cost estimates as these projects develop. This is the exact purpose of pursuing the development activities outlined in the Carbon Plan for new nuclear upon Commission approval.

Q. THE PUBLIC STAFF DOES NOT OPPOSE THE COMPANIES' PURSUIT OF SLR FOR ITS EXISTING FLEET BUT RAISES CONCERNS ABOUT MODELING OF COSTS.[17] WHY IS IT IMPORTANT TO RELICENSE THE COMPANIES' EXISTING NUCLEAR FLEET?

A. Relicensing the Companies' existing nuclear fleet is a vital step to ensure that the Companies can continue to serve base load generation that is a zero-carbon resource, one that currently provides over 50% of the electricity to our customers in North and South Carolina and provides approximately 83% of all of Duke Energy's carbon-free generation. The relicensing of the nuclear fleet provides the option for continued operation beyond the current 60-year license period. Since the Companies continue to invest in the nuclear fleet to maintain its safety and reliability, the payback period for the

[17] Public Staff Metz Direct Testimony at 30-32, 35.

cost of relicensing to allow extended operations is in the order of months and therefore was modeled as a baseline resource in all of the Companies' portfolios. The Companies project a commensurate spend profile for the fleet in the period of extended operations, as compared to current operations, when adjusted for inflation. The Companies believe that achieving the goals set by HB 951 will not be possible to implement from a reliability, cost, and executability perspective if the Companies forego relicensing of the existing nuclear fleet.

III. OFFSHORE WIND

Q. WHILE NOT AN ISSUE REQUIRING A COMMISSION DECISION, DO YOU HAVE RESPONSES TO CERTAIN CLAIMS MADE BY AVANGRID IN THIS PROCEEDING?

A. Yes. I would like to make a few corrections to the claims made by Avangrid. Avangrid states that "there is currently no turbine on the market that is rated to withstand the hurricane-force wind levels experienced in the [Carolina Long Bay] lease areas, forces which historically have not been present in the Kitty Hawk lease area."[18] This claim is incorrect because all major offshore wind turbine original equipment manufacturers (Vestas, Siemens Energy and GE) have 9, 11, 12 and 13 MW offshore wind turbines that have been certified to a Typhoon-class for use in the Asian market. Moreover, Avangrid's hurricane risk analysis fails to mention that Category 4 or

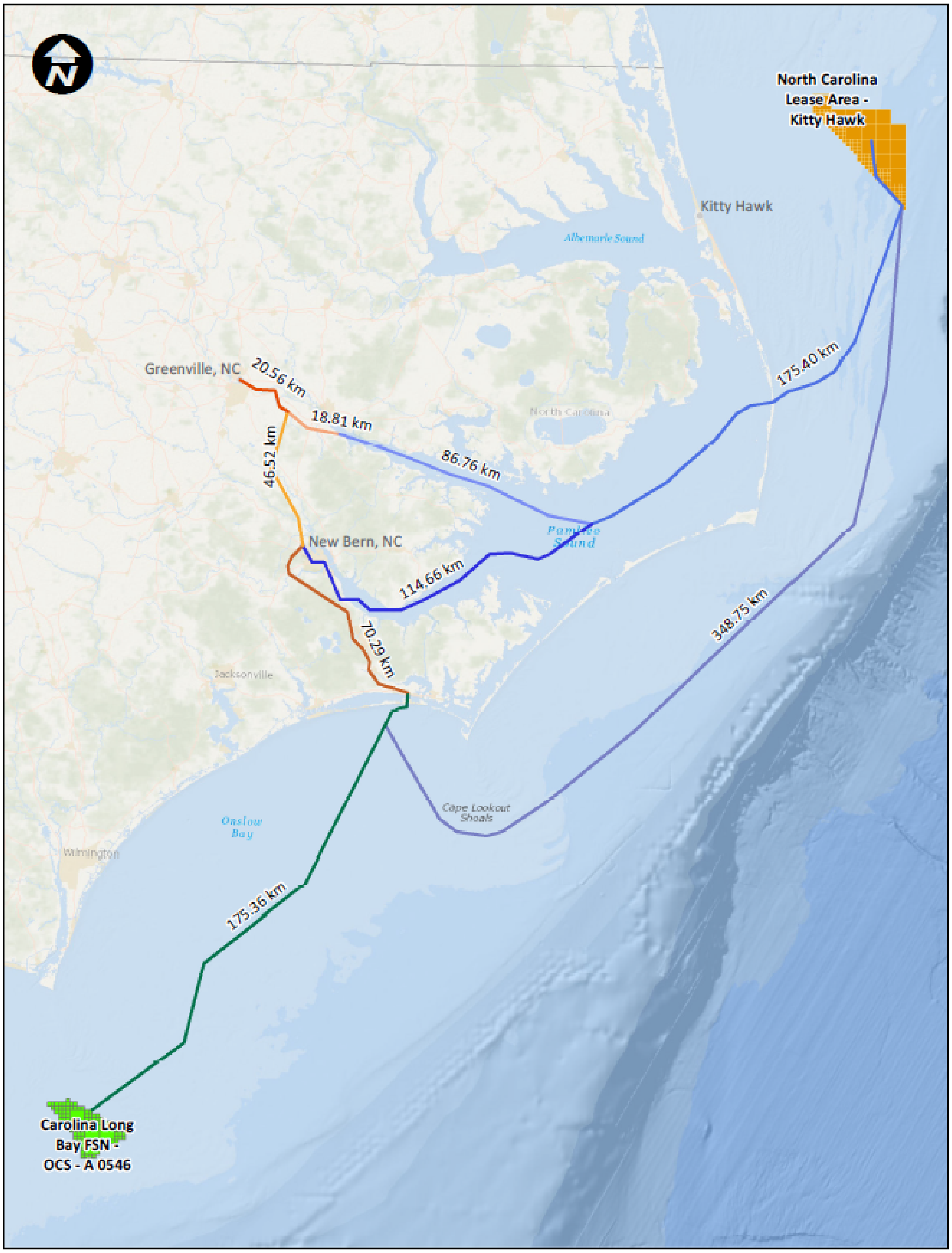
[18] Avangrid Starrett Direct Testimony at 19.

greater hurricane event probabilities are not significantly different for the Kitty Hawk lease area (<1%) versus the Carolina Long Bay lease area (<2%).

I would also like to address Avangrid's claims related to export cable length. Avangrid assesses that the export route from Kitty Hawk to the Havelock or New Bern substations is roughly 25 km longer than the distance from Carolina Long Bay ("CLB") to those substations.[19] Avangrid claims the 25 km difference represents a total project cost differential of less than 0.4%—a difference that they state is "not material to the business case."[20] The Companies disagree with Avangrid's analysis that the export route differential is only 25 km. Our analysis of transmission routing indicates an estimate of a longer cable by about 170 km. See Rebuttal Figure 1 for a map that compares the route alternatives.

[19] *See* Avangrid Starrett Direct Testimony at 21-22.
[20] *Id*.

Rebuttal Figure 1



POI	Est. Cable Route Length to Kitty Hawk (km)	Est. Cable Route Length to a CLB Lease (km)
New Bern	419	246

In addition, the shortest proposed path that we believe Avangrid refers to in their direct testimony may have significant environmental impacts as it crosses the Pamlico Sound and Neuse River, and other environmentally sensitive areas. Also, no cable route options with landfall locations in North Carolina are included in the publicly available Construction and Operations Plan for the Kitty Hawk project posted on BOEM's website last summer; only the landfall location near Sandbridge Beach in the City of Virginia Beach, Virginia is shown. As a result, we are unable to review public and agency comments on this route that would have been received during the public scoping period that BOEM held last summer. However, we believe that a cable route through Pamlico Sound introduces significant uncertainty due to challenges that could be encountered from a permitting, timing, and cost perspective, and it is likely that BOEM will require an assessment of multiple alternatives to a cable route through Pamlico Sound to reduce potential impacts. A path with lower environmental impacts would increase the offshore (subsea) transmission length to almost twice the length required to land a project in the Carolina Long Bay in the same area to get to the New Bern substation. The longer path is shown my Rebuttal Figure 1.

Lastly, I would like to address Avangrid's claims related to the difference in net capacity factors ("NCF") between the CLB and Kitty Hawk WEAs. Avangrid claims that the NCF for Kitty Hawk is superior to CLB, and that the CLB lease areas would generate a levelized cost of energy ("LCOE") of about $10 to $15 higher than Kitty Hawk's LCOE.[21] Determining the NCF of any lease area requires detailed site assessment planning and, at this time, the Companies do not believe that any party has performed the requisite analysis to definitively establish an NCF of 36% for the Carolina Long Bay WEA. The Companies' proposed development activities will include the deployment of meteorological equipment to assess the wind character in the area which will lead to detailed site assessment and development of NCF.

Q. DO YOU EXPECT THAT COMPLIANCE WITH THE JONES ACT WILL DELAY THE COMPANIES' OFFSHORE WIND PROJECTS?

A. No. The Companies agree with TotalEnergies[22] that the Jones Act will not delay the Companies' installation. The Companies expect that the Jones Act-compliant vessel supply market will increase to meet demand. Additionally, alternate arrangements for transport and construction vessels are available to meet the Jones Act.

[21] *See* Avangrid Starrett Direct Testimony at 22-23.
[22] TotalEnergies Prokopuk Direct Testimony at 14.

IV. CONCLUSION

Q. MR. REPKO, ARE THERE ANY FINAL TAKEAWAYS YOU WOULD LIKE TO SHARE WITH THE COMMISSION?

A. HB 951 presents a transformative change to how the Companies will generate electricity and reduce carbon emissions, and the Companies will need to pursue new technologies and generating sources to effectuate that change. By approving the decision to pursue near-term development activities and incur costs related to the three long lead-time resources, the Companies will be able to fully analyze the costs and benefits associated with these long lead-time resources, thus facilitating the Companies' ability to make these resources available to meet the 70% Interim Target and overall net zero goals of the Carbon Plan. Furthermore, these development activities have value for any future timeframe the resource is selected. The Companies propose these near-term development activities to have costs caps and propose to acquire a WEA from its affiliate, DERW, for the Carolina Long Bay, subject to future Commission acceptance of an appropriate affiliate filing pursuant to the requirements of Gen. Stat. § 62-153 in a separate proceeding.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Duke Energy Carolina, LLC and Duke Energy Progress, LLC
Summary of Rebuttal Testimony -
Regis Repko, Chris Nolan, And Clift Pompee
Carolinas Carbon Plan
Docket No. E-100, Sub 179

My name is Regis Repko and I am the Senior Vice President of Generation and Transmission Strategy for Duke Energy Carolinas, LLC and Duke Energy Progress, LLC. I am here today testifying together with Chris Nolan and Clift Pompee on the "Long Lead-Time Resources Panel." I will present a summary of my rebuttal testimony and that of Messrs. Nolan and Pompee.

The purpose of the Panel's rebuttal testimony is to reaffirm the Companies' request for approval of the decision to pursue near-term development activities and incur costs related to Bad Creek II, new nuclear technologies, and offshore wind. This Panel's rebuttal testimony also responds to certain comments, critiques, and recommendations offered in the Direct Testimonies of the Public Staff; the Attorney General's Office; TotalEnergies Renewables USA, LLC; Avangrid Renewables, LLC ("Avangrid"); CIGFUR II & III; and the Environmental Working Group.

The Companies continue to believe that it is reasonable and prudent to invest in the development of the three long lead-time resources to meet the ambitious carbon reduction goals established by House Bill 951. While there appears to be general consensus among the parties over the development of Bad Creek II, the Companies' position remains clear: Duke Energy will need all three long lead-time resources to generate the significant amount of carbon-free energy needed to meet the targets set forth by HB 951.

Also, I would like to reiterate what the Companies are asking for in this proceeding. To be clear, the Companies are not asking the Commission to select any of the long lead-time resources for inclusion in the Carbon Plan at this time. Rather, the Companies are asking the Commission to approve the decision to pursue near-term development activities and incur costs related to the three long lead-time resources. Approval of this request will, in part, allow Duke Energy to further analyze these long lead-time resources so that it can pursue initial "no regrets" work through activities like conducting a Pre-Feasibility/Feasibility Study for Bad Creek II, obtaining an Early Site Permit for small modular reactors ("SMR"), secure a Wind Energy Area ("WEA") lease, and complete a Site Assessment Plan ("SAP") for that WEA. These initial efforts are beneficial in that once permits are completed, they retain value for use in the future and also preserve the potential to be able to use one or more of these resources to meet the targets of the Carbon Plan. The Companies believe it is reasonable for development costs to be capped at the amounts in Rebuttal Table 1 (which shall not be exceeded without further Commission approval).

Rebuttal Table 1

Long Lead-Time Resource	Proposed Development Cost Cap (2022-2024)
Offshore Wind	$325 million[1]
Nuclear	$75 million[2]
Bad Creek II	$40 million

While there is less consensus around new nuclear technologies and offshore wind, the Companies believe that pursuing development activities for these resources is necessary to maintain resource selection optionality for the Commission. The critiques of SMR technology mistakenly attempt to use the issues that faced the reactor designs of the 2000s to prejudice these new nuclear designs. As for offshore wind, Avangrid offers recommendations that rely on unsupported claims and analyses of the various wind energy areas. But, by approving the Companies' request, Duke Energy will be able to take the necessary steps to further analyze these resources in terms of costs and timelines to be able to assess when to bring these resources in a cost-effective manner to the Commission for selection in a future Carbon Plan proceeding.

While the Companies remain open to opportunities for cost-effective offshore wind WEAs to develop on behalf of customers, the Companies have concerns that the parties continue to propose arrangements that do not meet the ownership requirements of HB 951 and procuring a WEA from these parties carries timing, cost and certainty risk in contrast with the development option that is most readily and directly available to the Companies at a known, certain and reasonable cost that equals market price.

Therefore, the Companies believe the best and most certain path is to acquire the Carolina Long Bay WEA from their affiliate Duke Energy Renewables Wind, LLC ("DERW"). The Companies would make the appropriate affiliate filing under North Carolina General Statutes in a separate proceeding in early 2023, and Commission approval of the decision to acquire the lease in this proceeding would be effectuated in that separate proceeding. This path has four primary benefits, it (i) is simple and straightforward; (ii) has certainty of timing and cost; (iii) meets the utility ownership requirements of HB 951; and (iv) does not foreclose other options but ensures that at least one offshore WEA is available on a future timeline for offshore wind development desired by the Commission.

In closing, the Companies will need to pursue new technologies and generating sources to meet the transformative change that HB 951 presents. By approving the decision to pursue the near-term development activities and incur costs related to the three long lead-time resources, the Companies will be able to fully analyze the costs and benefits

[1] Includes estimated cost of obtaining an offshore wind lease.

[2] Costs associated with development work needed to obtain an Early Site Permit for a single site.

associated with these long lead-time resources, thus facilitating the Commission's ability to make these resources available to meet the 70% Interim Target and overall net zero goals of the Carbon Plan. This concludes the summary of this Panel's rebuttal testimony.

MS. LINK: And the panel is now available for questions from the parties and the Commission on its rebuttal testimony.

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

MR. SMITH: Chair Mitchell, Avangrid was able to review the record from the direct, and we think we've gotten everything that we need at this time, so we have no further questions.

CHAIR MITCHELL: Okay. CIGFUR?

MS. CRESS: In the interest of time, CIGFUR is also going to waive cross of this panel. Thanks.

MR. BURNS: CCEBA as well.

CHAIR MITCHELL: All right. CPSA?

MR. SNOWDEN: CPSA waives cross on this panel.

CHAIR MITCHELL: SACE?

MS. THOMPSON: No questions, Chair Mitchell. Thank you.

MR. SCHAUER: No questions from Tech Customers.

CHAIR MITCHELL: All right. Public Staff?

MS. GRUNDMANN: Chair Mitchell, I do have one question that was deferred this morning.

CHAIR MITCHELL: Okay.

CROSS EXAMINATION BY MS. GRUNDMANN:

Q. Good afternoon, gentlemen. In response to a question that I asked Ms. Bateman, I believe she deferred it to your panel, so I'm just gonna ask you it to you. It related to CPCNs.

Are there any long lead-time resources for which the Company does not intend to seek a CPCN or would not intend to seek a CPCN?

A. (Regis Repko) Directly relative to generation resources, we would file a CECPN for South Carolina for Bad Creek. Offshore wind, again, if selected by the Commission, would be in federal waters; however, there would be a CPCN for the supporting transmission of it, or any supporting transmission of it.

Q. Okay. So offshore wind, the project, itself, is in federal waters, would not have a CPCN, but the related projects within the confines of the state of North Carolina would?

A. Correct.

MS. GRUNDMANN: Thank you. Those are

all the questions that I have.

CHAIR MITCHELL: All right. Public Staff?

MR. FREEMAN: Thank you, Commissioner. I would like to hand out some documents now, if I may.

CHAIR MITCHELL: Go ahead. Help him.

(Pause.)

CHAIR MITCHELL: All right. Why don't we go ahead and mark the documents.

MR. FREEMAN: Thank you, Chair. We have one document is a lease, and the second document is an excerpt from the Code of Federal Regulations. I would propose to mark these as Public Staff Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibit Numbers 1 and 2.

CHAIR MITCHELL: All right. The federal regs will be identified as Public Staff Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibit Number 1, and the lease will be marked as Public Staff Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibit 2.

(Public Staff Long Lead-Time Resources

Panel Rebuttal Testimony Cross Examination Exhibits 1 and 2 were marked for identification.)

MR. FREEMAN: Thank you. Thank you, Chair and Commissioners.

CROSS EXAMINATION BY MR. FREEMAN:

Q. Thank you, panelists, for your time today. My name is Will Freeman. I'm an attorney with the Public Staff. I'm representing the using and consuming public. And, panelists, I would like to respectfully push back on some of the rebuttal testimony that was filed in this case. I was looking, in particular, on page 7, lines 10 through 12. But I think that idea, sort of, percolates through all of the testimony.

And just while you turn, I believe it states, "The Public Staff's position, if adopted by the Commission, would effectively eliminate the ability to keep offshore wind as an option to meet the 70 percent interim target of the Carbon Plan."

And so I'd like to discuss some -- some areas of respectful disagreement with respect to that testimony. I think that one area is we can agree that Portfolio 3 did not select offshore wind at all, and Portfolios 5 and 6 did not select offshore wind before

2040.

Is that y'all's understanding as well?

A. (Regis Repko) That is correct. That's my understanding.

Q. So now I'd like to talk about the other half of the portfolios that do select offshore wind in the near-term. And just -- we'll just go head on respectfully together. The first document, I believe, was the federal regulations, and the second document was the lease. And I gave you and your attorneys a copy of the whole federal regulations, but I also just took a few paragraphs out and highlighted. So you should have both of those.

A. Yeah, I do.

Q. Great. So the lease, I went to BOEM.gov and pulled the lease in. And you see on first page of that lease, in Section 1, it references -- about the third line down, it references 30CFR, part 858 [sic]. And that is the first exhibit I gave you, a few pages from that, but then again you have the whole part 585 right there should you want to refer to it.

A. Understand.

Q. Okay. So let's start with Exhibit 1, if you don't mind. If you'll look on the very last page of this four-page exhibit, which is numbered 584, and the highlighting was done by me. I'll read 585.601 with ellipses, and we'll start maybe at subsection A.

Duke Wind, quote, must submit your SAP no later than 12 months from the date of the lease.

Did I get that right?

A. It says that.

Q. Thank you.

A. (Clift Pompee) Excuse me, I believe you said "must," but in the document here, it says "may."

Q. I'm sorry. I had started on the third line down of subsection A. You may submit your SAP prior, but must submit your SAP --

A. Okay.

Q. -- or your GAP no later than --

MS. LINK: Counsel, may I ask, which document are you in?

MR. FREEMAN: I'm on the last page of Exhibit 1, the number on the page is 584, I'm looking at the highlighted Section A. The third line down says, "Must submit your SAP." And that's why we're having this testimony so that we can talk about the statute and what words it uses.

Q. Mr. Pompee, are you -- I'm glad to -- if you'd like to look this over --

A. No, no, I -- I got what you are saying. I apologize. I misread which line you're on.

Q. Again, this is -- you know, this isn't an inquisition, this is for us to talk about what the law says.

Subsection B on the last page of 584 uses the same word "must" as well. Duke Wind, quote, must submit a COP or FERC license application at least six months before the end of your site assessment term.

Did I get everything right?

A. Yes.

A. (Regis Repko) Yes.

Q. Okay. Let's pause on the law and then move to the lease, which is Exhibit 2. And if you'll look with me on -- the page number is C-3, it's in Section 3.1 about three-fourths of the way down on the page. I'd like to read it, but I would like to substitute the name of the parties instead of saying lessor and lessee.

Are you-all with me? I'm not trying to rush you?

A. No. What section or page?

Q. 3.1, page C-3 of Exhibit 2.

A. I'm there.

Q. Okay. Okay. Again, I'm reading with substituting the name of the parties.

"Duke Wind must submit to the United States of America a progress report every six months," open parentheses, "unless BOEM directs otherwise," close parentheses, "through the duration of the site assessment term that includes a brief narrative of the overall progress since the last progress report or, in the case of the first report, since the effective date."

Did you see where I was and did I read it correctly?

A. Yes.

Q. Thank you so much. Now, let's pause on the law and the part I just read, and if we can go -- if you'll look with me in the lease, Exhibit 2, on page 1, the effective date is June 1, 2022.

A. Correct.

Q. Thank you. And if you'll look with me on page B-1, the site assessment term is five years, and the preliminary term is one year.

A. Correct.

Q. Okay. Thank you. Can -- excuse me.

Can we agree that Duke Wind must submit a progress report with a brief narrative starting on January 1, 2023, unless BOEM says otherwise?

A. With the -- only with the exception of BOEM, correct.

Q. Okay. Can we also agree that Duke Wind must submit an SAP, that stands for site assessment plan, before June 1, 2023, unless Duke Wind asks for more time?

A. Correct.

Q. And can we agree that Duke Wind must submit a COP, that's a construction operations plan, before December 1, 2026, unless Duke Wind asks for more time?

A. Correct.

Q. Okay. Now, I would like to discuss with y'all what happens if Duke Wind doesn't receive more time or doesn't comply with these obligations that we just discussed. And if we go back to the regulations, which I think were Exhibit 1, if you'll turn to the second page of Exhibit 1, which is page number 54 -- 564. I've highlighted it as well for ease of reference.

If we can look at Section 585.400(b), BOEM may issue to you, and you in this case is Duke Wind, a notice of noncompliance if we, the government agency, determine that there has been a violation of the regulations in this part or any provision of your lease.

Did you see where I was reading from?

A. I did.

Q. Okay. And now we can come down to the section -- subsection D, also highlighted. And failure of Duke wind to address the noncompliance is the basis for a, quote, a cancellation, correct? Subsection D, last -- next-from-the-last line, cancellation.

A. (Witness peruses document.)

Correct.

Q. Okay. Now, if you'll turn one more page, it's numbered page 570, this is subsection B. Again, we get back to the cancellation as an option.

A lease may be canceled if Duke Wind, quote, has failed to comply with -- I'm gonna read with ellipses -- has failed to comply with these regulations or any term, condition, or stipulation contained in the lease.

A. Correct.

Q. Thank you. All right. So let me talk about one more place where we discuss what can happen in the event of noncompliance. It's on Section 8. Exhibit 2, the lease, Section 8, page 3. Near the bottom of page 3. And I hope no one gets a paper cut, I apologize. I'm gonna read again with ellipses, and I'm gonna substitute the name of the parties. Section 8, page 3. Not A-3, page 3.

If Duke Wind fails to comply with, 1, any of the applicable provisions of the act or regulations -- I'm gonna skip 2 -- or 3, the terms of this lease, including any associated addenda, the United States of America may exercise any of the remedies that are provided under the act and the applicable regulations including, without limitation, issuance of cessation of operations, orders, suspension, or cancellation of the lease and/or the imposition of penalties.

A. Yes.

Q. Thank you. So can we agree that, if Duke Wind doesn't get more time, Duke Wind runs the risk of having the Carolina Long Bay lease canceled if it doesn't move forward with filing an SAP, a site assessment plan, or providing BOEM with progress reports every six months and filing a COP, construction operations plan, within five years?

A. Yes, I agree. I believe that's consistent with what we said in our direct testimony.

Q. But Duke Wind very much wants to avoid that, doesn't it?

MS. LINK: Objection. These gentlemen made very clear on direct that they are not a part of Duke Energy Renewables Wind. Can't speak on behalf of that entity.

Q. Hypothetically, if you had a wind -- offshore wind company, would you very much want to avoid cancellation?

A. It would depend on the market. You know, here's the point we brought out in direct testimony. So agree it says all those things. What I don't know is where is the provision for BOEM to grant extensions, because they have done so. You know, BOEM has a very limited staff. Their objective is to advance the development of offshore wind. And they were very much focused with developing leases and auctioning leases in the Northeast.

They pivoted down to what is now Carolina Long Bay because of the energy expiration moratorium that was gonna take place in July of this year. So it is reasonable to assume they will focus their resources back to auctions, whether it be Northeast gulf or the

West Coast, where they see a market, where they see a future market.

So they really -- they have granted extensions because they really have no interest in acquiring leases back. It defeats the whole purpose of, you know, what their objective is, in terms of developing offshore wind.

Q. Well --

A. (Witness peruses document.)

Q. I didn't know if you had an additional point you wanted to bring up or not.

A. Mr. Nolan just highlighted a section in Exhibit 1 at the very bottom of paragraph 1, top of the second paragraph that elaborates on extensions.

Q. Extensions are absolutely permitted.

A. Permitted, yeah.

Q. Okay. Does it make economic sense for an offshore wind company to spend a fair amount of money and then take no steps to develop that asset?

A. It would depend on where they see -- if they see a future market and what that would look like.

Q. Okay. Have you had any conversations with Duke Wind about whether it intends to seek more time to comply with these obligations we've discussed?

A. I have not.

Q. Have you had any -- or the panel, I don't mean you.

Has the panel had any conversations with Duke Wind about whether it intends to move forward with the SAP before June 1, 2023, the annual deadline?

A. The last information -- really, the only information I had was shortly after the auction when, in a meeting, there was discussion that Duke Energy Renewables Wind was procuring resources to initiate the SAP. Haven't heard anything beyond that or since then.

Q. I think that we can agree that the time frame proposed by the panel in its testimony contemplated that Duke Energy would work on the SAP and the COP?

A. (Clift Pompee) Are we talking about the direct testimony or the rebuttal?

Q. Direct. I apologize.

A. Okay. So the time frame that was placed in the direct testimony was a time frame for the regulated utility, what we postulated would be our timeline.

Q. And that was the 8- to 10-year timeline?

A. That's correct.

Q. Part of that timeline included some time for the SAP and some time for the COP?

A. It did. And, as I mentioned in my direct testimony, if you look at the timeline provided by BOEM, and I think you show that here, the site assessment period is five years. So, you know, you mention 2026. December, five years is June 2027.

Q. I was backing the six months out but, it's close, right?

A. Okay. Understood.

Q. All right.

A. So Duke Energy Renewables Wind, in this hypothetical situation, is five years to submit a COP. I agree. One year SAP is pretty straight. Up to five years to submit a COP. What we were saying was that, if the Commission would like to have the option for offshore wind in the 2030s, in the early 2030s, that there is no obligation for Duke Energy Renewables Wind to accelerate the timeline and get a COP in three years, right? The requirement is five. If we look at the -- and you can do five. And you can have your progress reports and be within the law and still get five years to do a COP.

Now, aside from that, we've seen Dominion, for example, they got their lease in 2013, didn't file a COP until 2020. They worked with BOEM based on their particular situation to get an extension. Now, I don't know what Duke Energy Renewables Wind is doing, but the five years to get a COP would put us, I believe, behind where we would need to be if we want to get offshore wind in the 2030s.

Q. So we can agree that, if Duke Wind did move expeditiously -- Duke Wind or any hypothetical offshore wind owner did move expeditiously, we would not miss out on the -- half of the -- the near-term actions necessary for offshore wind to come online in Portfolios 1, 2, and 4?

A. (Regis Repko) That's correct. But I think you make my point, "if." You know, what we are asking for, really from a directional standpoint, is, from the Commission, that these three long lead resources: pump storage, SMRs, offshore wind, initiate development so that they are ready.

And the proposal that we have, the solution that we have is for the lease to go to a regulated -- to the regulated Companies, DEP specifically, to be developed with full transparency, oversight, and progress relative to the development activities that we have asked for and on the timeline that we have asked for.

Q. Have you had discussions with Duke Wind about entering into a nondisclosure agreement and working through the details of Duke Wind taking any activities?

A. We have not.

Q. Okay. Do you think a, let's say, study ordered by the Commission would encourage Duke Wind to move expeditiously so this could be an asset available for Duke Energy in the next Carbon Plan?

MS. LINK: Chair Mitchell, I'd object. It was clear in the direct testimony, and I believe also in the Public Staff's testimony, that this Commission doesn't have jurisdiction over DukeEnergy Renewables Wind as an affiliate.

MR. FREEMAN: Would it make sense for it -- I apologize, Chair, I didn't mean to -- I'd like to rephrase my question.

CHAIR MITCHELL: All right. I'll overrule. Rephrase.

MR. FREEMAN: Thank you.

Q. Would it make sense for a generic offshore wind company, that if it received a signal from the Commission that a study was forthcoming, that its asset would be more valuable if it could start on these -- well, the SAP's due in a year, but start on the COP which has the up-to-five-year time frame?

A. It would be consideration, but they'd have to look at the other market factors.

Q. Okay. I understand.

MR. FREEMAN: If I could have one moment, Chair and Commissioners.

(Pause.)

Q. Thank you very much, panelists.

MR. FREEMAN: Thank you very much, Chair and Commissioners. I don't have any more questions.

CHAIR MITCHELL: All right. Redirect.

MS. LINK: Thank you, Chair Mitchell.

REDIRECT EXAMINATION BY MS. LINK:

Q. For the panel, just for clarity purposes, under the Duke Energy Renewables Wind lease that was effective as of June 1, 2022, when does a COP, a constructions operation plan, need to be submitted to BOEM? I believe you said it, Mr. Pompee, but maybe we could just be -- to clarify.

A. (Clift Pompee) That would be June of 2027, five years after the lease execution date.

Q. Okay. So there was some discussion of a December 1, 2026, date. You don't agree with that date, correct?

A. I do not.

Q. Okay. There was some discussion, Mr. Repko, about -- and, Mr. Pompee, about getting extensions from BOEM. And I believe you talked about Dominion getting an extension from BOEM to file their COP seven years after they won the lease in auction, correct?

A. Correct.

Q. Can you turn to -- it's Public Staff Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibit 2, page B-1.

MR. FREEMAN: B?

MS. LINK: B, as in boy.

Q. And on the page, it is called addendum B, lease term and financial schedule. And under lease term, where it lays out lease terms, it says, "The duration of each term of the lease is described below."

Could you read the next sentence, Mr. Pompee?

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

Q. Oh, you're not on the same page?

A. I'm not there yet, yeah. Page bravo 1?

Q. Bravo 1.

A. Okay.

Q. Are you there, sir?

A. I am on the page.
Q. Okay. Top of the page, lease term?
A. Correct. Okay.
Q. After the sentence, "The duration of each term of the lease is described below," what does that next sentence say?
A. "The terms may be extended or otherwise modified in accordance with applicable regulations in 30CFR part 585."
Q. Okay. And below then are the lease terms. These extensions and modifications are what you're talking about that Dominion took advantage of?
A. Correct.
Q. Okay. And is it your understanding that those extensions are granted on a regular basis?
A. They -- it is my understanding that they are. To Mr. Repko's testimony, BOEM has every intention of working with the lessee to ensure success for the lease.
Q. Thank you.

MS. LINK: Chair Mitchell, there was also some questioning from Walmart counsel about CPCN authority for Bad Creek II, and I do believe that was a question from Chair Mitchell as well, about whether there was going to be authority granted from the South Carolina Commission. At the appropriate time, if you would like to ask your question again, or I can respond to it. It has a legal component to it, so just for clarity at the right time, if it's all right with you, I would prefer to answer that question.

CHAIR MITCHELL: All right. Well, I was gonna pose that question to the panel, so.

MS. LINK: We can wait.

CHAIR MITCHELL: Yeah, when we get there.

MS. LINK: Thank you. I have no further redirect.

CHAIR MITCHELL: All right. Questions from Commissioners? Commissioner Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Gentlemen, I've got an arithmetic question just to be sure I'm understanding one of your exhibits right. So with reference to the last page of your rebuttal testimony and then the Figure 1 that follows that last page, you were on the last page on lines 10 through the end of the page. You're disputing Avangrid's calculus of the differential export route for the undersea cable. And you say you think the difference is that their cable would be longer by about 170 kilometers.

And then I look at Figure 1 and I'm trying to -- there are a lot of numbers on Figure 1 and a lot of different routes.

Is the way I get to the 170-kilometer difference, is that by comparing the green line difference from the Carolina Long Bay to the point near Emerald Isle and then comparing that to the blue line that moves south from the Kitty Hawk area down toward Cape Lookout Shoals and then comes in towards Emerald Isle? Is that the line I look at to compare to get 170-kilometer difference?

A. (Clift Pompee) Okay. I want to answer with a yes or no, but unfortunately the one in front of me is black and white, so I'm gonna --

MS. LINK: Permission to --

THE WITNESS: -- I'm gonna walk through it.

MS. LINK: Permission to provide a color copy?

COMMISSIONER CLODFELTER: Okay.

THE WITNESS: All right. So if you

wouldn't mind walking me through the colors again.
Q. Well, I think your counsel is gonna give you a -- so you see on the figure there now you have color one?
A. I do, I've got it.
Q. And it shows the Carolina Long Bay lease area is in green, and then there's a green line which is the undersea cable, I assume, that goes north to a point that's roughly around Emerald Isle to the coast, and then there's the Kitty Hawk area up in orange?
A. Yes.
Q. And then coming south from that there are two lines, but one of them comes most directly south, then continues down over Cape Lookout Shoals and then turns inland toward Emerald Isle. And it looks to me that the difference between those two lines is 170 kilometers. Are those the two lines that are being compared in the written testimony?
A. That is correct.
Q. Got it.
A. And what we did was we assumed, for the purposes of one-to-one comparison, that the landing spot would be the same. That way we could show exactly the delta.

Q. I understand. It's just that there were several other possible routing combinations on the -- and I just wanted to be sure I was comparing the right ones to get 170 kilometers. You've answered my question, thank you. That's all.

EXAMINATION BY CHAIR MITCHELL:

Q. All right. Gentlemen, do you-all know whether -- let me start this way.

Ms. Repko, I heard your testimony a moment ago that Bad Creek II would have to secure a CECPCN, and that would be from which jurisdiction?

MS. LINK: Chair Mitchell, if it's all right, since it has a legal component, if I can provide --

CHAIR MITCHELL: Yeah, go ahead. And then I may ask you-all to file a late-filed exhibit just explaining your response.

MS. LINK: Sure. My understanding is that, under South Carolina law, a -- pardon me.

(Pause.)

MS. LINK: The Hydro-electric generating facility that's regulated by the Federal Energy Regulatory Commission, if the relicensing takes place at FERC, you do not have to get a CPCN from the South Carolina Commission. However, the Company could waive that requirement and seek a CPCN from the South Carolina Commission.

CHAIR MITCHELL: Okay.

MS. LINK: So although a final decision hasn't been made yet, the Company is leaning towards taking advantage of that waiver and seeking a CPCN before the South Carolina Commission, although a final decision hasn't been made yet.

CHAIR MITCHELL: Ms. Link, is there -- is that pursuant to federal regulation?

MS. LINK: That is -- so the relicensing of Bad Creek II is, sort of, folded into the licensing of Bad Creek I, and it is under FERC jurisdiction.

CHAIR MITCHELL: Okay. And it's South Carolina law that no CPCN is necessary if there's relicensing or licensing ongoing at the federal level?

MS. LINK: Specifically for a hydro-electric generating facility.

CHAIR MITCHELL: Specifically for hydro.

MS. LINK: Which is what Bad Creek is.

CHAIR MITCHELL: Okay.

MS. LINK: So it would -- it's a choice.

CHAIR MITCHELL: Understood. Okay. All right. Let me see if there are any other questions from Commissioners. I've got questions that are gonna take us into confidential session. So with that, I would ask that we clear the room. Duke, make sure you -- this is gonna pertain to confidential information pursuant to the Avangrid agreement. So I'm not sure how y'all want to handle that, but anyone who is not pretty privy to that agreement needs to clear the room. And I would ask that we cease the streaming and we'll go into confidential session.

MR. SMITH: Just so we're clear, this is confidential session consistent with the way it's practiced during this proceeding, where there's no further requirements at this time, any further requirements pursuant to the agreement between Avangrid and Duke that will come up in a response, a sort of canned response?

MS. LINK: I'm sorry, Mr. Smith.

MR. SMITH: I was getting questions for other parties who had signed the broader NDA had to leave, and I wanted to clarify for them that they didn't have to.

MS. LINK: Right. So we agreed that the broader -- the NDA that the parties have signed in this proceeding would cover these discussions. And -- okay.

(Due to the proprietary nature of the testimony found on pages 145 to 164, it was filed under seal.)

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(Confidential testimony ended at 4:30 p.m.)

CHAIR MITCHELL: Okay. All right. We will go out of confidential session and go back into public session, and you can let people back in the room.

Okay. We have just three more questions for you, Mr. Repko, or two more really.

EXAMINATION BY CHAIR MITCHELL:

Q. Did you -- has the Company -- has Duke, any of the Duke entities -- I'm getting a signal. Your panelists want to rejoin you?

CHAIR MITCHELL: You can't find them? They've left the building? They had enough. Can you get Mr. Eason in the room, please? Okay.

Q. Has any of the Duke entities had discussions with TotalEnergies about its lease?

A. (Regis Repko) There were -- there were initial discussions around -- before the lease about a potential partnership to participate in the auction. We explained the ownership provisions of House Bill 951. There were also -- again, nothing progressed past that. There have also since been discussions about opportunities around co-development of the SAP since it is a common geographical area. But nothing more than that.

Q. Would co-development of the SAP save ratepayers money?

A. There would -- there would be savings there. The magnitudes, again, I would have to -- I don't have. You know, default of Duke Energy Renewables Wind on that.

Q. Understood. But it's likely that there would be some savings?

A. There would be, yes.

Q. Any other opportunities to identify and realize ratepayer savings associated with the proximity of Total's lease?

A. Well, I mean, all of the development activities, because of the proximity, right, the meteorological wind speed, the ocean floor surveys, those are -- you get into some pretty expensive-type activities. So, obviously, there would be cost savings associated with the share of those -- sharing those.

Q. And that's something that -- the sharing is an avenue the Companies either have begun to explore or will explore in the future?

A. There are discussions, yes.

CHAIR MITCHELL: Okay. All right.

Questions on those -- I'm sorry, Commissioner

Clodfelter.

EXAMINATION BY COMMISSIONER CLODFELTER:

Q. Let me follow the Chair's question on that -- that point about the options for shared costs.

Could those go so far as shared infrastructure, such as shared cabling and shared onshore facilities necessary to get to the injection point? Could those be co-developed with Total?

A. I'd have to think -- we'd have to look at that around the provisions of House Bill 951 ownership, but I'll say potentially.

Q. I respect that. I'm just really asking more if there were technological or physical barriers that would prevent you from talking with them about shared infrastructure?

A. No, there is not.

CHAIR MITCHELL: Okay. I believe we've come to the end of this panel's cross examination.

MS. LINK: We have no exhibits.

CHAIR MITCHELL: Any -- go ahead.

MR. FREEMAN: We had two exhibits, Commissioner. I would move the Public Staff's Long Lead-Time Resources Panel Rebuttal Testimony Cross Examination Exhibit Numbers 1, which were the portion of the Code of Federal Regulations, and Exhibit Number 2 which was the lease into the record in evidence.

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

MR. FREEMAN: Thank you.

(Public Staff's Long Lead-Time Resources Panel Rebuttal Cross Examination Exhibit Numbers 1 and 2 were admitted into evidence.)

CHAIR MITCHELL: All right. With that, you-all may step down and be excused. Thank you very much for your testimony today. All right.

Duke, call your next witnesses.

(Pause.)

CHAIR MITCHELL: All right. Let's get you all sworn in. Please raise right hands.

Whereupon,

LON HUBER AND TIM DUFF,

having first been duly sworn, were examined

and testified as follows:

CHAIR MITCHELL: All right.

MS. FENTRESS: Madam Chair, this is the Grid Panel that has been -- Grid Edge Panel, sorry, that has been recalled. Today Duke Energy filed a late-filed exhibit at the request of the Commission, late-filed Exhibit Number 6. With the Commission's permission, I can have that -- I can ask the panel to introduce that exhibit and ask that it be premarked.

CHAIR MITCHELL: I would appreciate that. Do you have copies? Okay.

MS. FENTRESS: I have copies if the Commission does not have copies.

CHAIR MITCHELL: I don't think we have copies.

MS. FENTRESS: We have copies.

CHAIR MITCHELL: Okay.

(Pause.)

MS. FENTRESS: While they're being passed out, I could take care of some of the preliminary questions.

CHAIR MITCHELL: All right. Go ahead.

DIRECT EXAMINATION BY MS. FENTRESS:

Q. Beginning with Mr. Huber.

Mr. Huber, are you the same Lon Huber who appeared in this proceeding on September 16, 2022, as part of the Grid Edge Panel's direct case?

A. (Lon Huber) Yes.
Q. And, Mr. Duff, are you the same Timothy Duff who appeared with Mr. Huber on September 16th?
A. (Tim Duff) Yes.
Q. Turning back to you, Mr. Huber, did the panel cause to be prefiled in this docket rebuttal testimony consisting of 16 pages?
A. (Lon Huber) Yes.
Q. Do you have any changes to your rebuttal testimony at this time?
A. No.
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 this panel's testimony include confidential information?
A. No.
Q. Did you also cause -- prepare and cause to be prefiled a summary of the panel's rebuttal testimony?
A. Yes.
Q. And did this panel, at the Commission's request, prepare and cause to be filed late exhibit -- Late-Filed Exhibit Number 6?

A. Yes.
Q. Do you have any changes to make at this time to Late-Filed Exhibit Number 6?
A. No, not at this time.
Q. Does Late-Filed Exhibit Number 6 include any confidential information?
A. No, it does not.

MS. FENTRESS: Chair Mitchell, I would ask that the Grid Edge Panel's rebuttal testimony be entered into the record as if given orally from the stand, and that the late-filed exhibit be premarked.

CHAIR MITCHELL: All right. The rebuttal testimony -- the prefiled rebuttal testimony of the Grid Edge Panel will be copied into the record as if delivered orally from the stand. And the late-filed -- let's mark the late-filed exhibit as Grid Edge Panel Rebuttal Exhibit 1.

(Grid Edge Panel Rebuttal Exhibit 1 was identified as it was marked when prefiled.)

(Whereupon, the prefiled rebuttal testimony of Lon Huber and Tim Duff and the prefiled summary testimony of Lon Huber and Tim Duff, as requested in Volume 30, 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	)	**LON HUBER AND TIM DUFF 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. MR. HUBER, PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is Lon Huber, and my business address is 526 South Church Street, Charlotte, North Carolina, 28202. I am the Senior Vice President for Pricing and Customer Solutions for Duke Energy Corporation. I am providing testimony today with Tim Duff on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") as the "Grid Edge Panel." Mr. Duff will introduce himself.

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

A. My name is Timothy J. Duff, and my business address is 400 South Tryon Street, Charlotte, North Carolina, 28202. I am the General Manager, Grid Strategy Enablement for Duke Energy Business Services, LLC.

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

A. Yes.

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

A. No.

Q. WHAT IS THE PURPOSE OF THE GRID EDGE PANEL'S REBUTTAL TESTIMONY?

A. The purpose of the Grid Edge Panel's rebuttal testimony is to respond to the testimony of the Public Staff - North Carolina Utilities Commission ("Public Staff") witness David M. Williamson, the North Carolina Attorney General's Office ("AGO") witness Edward Burgess, Appalachian Voices witness Rory McIlmoil, Carolina Industrial Group for Fair Utility Rates II and III ("CIGFUR") witness Michael P. Gorman, and NC WARN witness William E. Powers.

Q. PLEASE EXPLAIN THE GRID EDGE PANEL'S APPROACH TO REBUTTAL TESTIMONY IN THIS PROCEEDING.

A. The Companies are taking a targeted approach to rebuttal testimony due to the significantly accelerated procedural schedule in this proceeding. The Companies continue to believe that the energy efficiency modeling assumption of 1% of eligible load is reasonable and supports the near-term action plan presented for approval in this initial Carbon Plan proceeding. Approval of the near-term action plan will allow the Commission to retain discretion to consider all available options in future Carbon Plan biennial update proceedings as the energy transition continues. The Grid Edge Panel will address the most significant comments and critiques of the Grid Edge direct testimony presented by the Public Staff, the AGO, Appalachian Voices, CIGFUR, and NC WARN, but the panel has not undertaken the unachievable task of responding in four business days to every issue presented by the various witnesses that address Grid Edge issues.

II. RESPONSE TO PUBLIC STAFF

Q. DO YOU AGREE WITH PUBLIC STAFF THAT THE DEMAND-SIDE MANAGEMENT ("DSM")/ENERGY EFFICIENCY ("EE") MECHANISM NEEDS TO BE REOPENED TO MAKE THE COMPANIES' PROPOSED UPDATES?

A. No. After a Carbon Plan is adopted by the Commission, the Companies agree that any updates to the inputs utilized for justifying demand-side utility programs must be part of a Commission-approved modification to the EE/DSM Cost Recovery Mechanisms ("Mechanism"). The changes to the Mechanism that would base inputs on the specific costs associated with the selected marginal carbon free and storage resources in the approved Carbon Plan need to be developed in collaboration with stakeholders and approved by Commission. However, the entire Mechanism, which was approved two years ago after months of negotiation and comment among numerous parties, does not need to be reopened and modified. Instead, the Companies recommend that targeted required modifications to the Mechanism be approved by the Commission. This will facilitate a more expedited process than the unnecessary complexity of reopening the entire Mechanism, which includes other, unrelated provisions and is formally reviewed by the parties and the Commission approximately every four years. Following the Commission's current existing review schedule, the

Mechanism is not slated to be reopened for comprehensive update and review until 2024.

There is established precedent for targeted modifications to the Mechanism that supports the Companies' proposal for the targeted modification of the Mechanism in this case. As the Commission is aware, in the past year, both Companies worked with the Public Staff on developing specific language modifying the Mechanism to include application of the Reserve Margin Adjustment Factor in the determination of the avoided capacity values associated with energy efficiency savings. The Companies proposed the specific, agreed-upon modifying language for review in their respective annual DSM/EE rider filings, without requiring any additional changes to the Mechanism.

Q. PLEASE COMMENT ON WITNESS WILLIAMSON'S STATEMENT THAT THE COMPANIES' "AS-FOUND" BASELINE METHODOLOGY IS INAPPROPRIATE FOR ANY EE MEASURE WITH AN IDENTIFIED BASELINE EFFICIENCY.

A. Notably, the Companies agree with the Public Staff that the appropriate time to address the "as-found" baseline is when the Companies request Commission approval for new programs or modifications to existing programs that seek to recognize and measure energy savings on an "as-found" basis. The Companies disagree, however, with witness Williamson's contention that the "as-found" baseline should not apply to measures that have baseline efficiency standards. Witness Williamson's overly broad recommendation fails to recognize the link between "as-found" savings and programs that promote early replacement of measures. The Companies' Mechanisms neither prescribe nor prohibit the use of an "as-found" baseline, but rather require that the energy savings are Evaluated, Measured and Verified ("EM&V") by an independent third-party using industry-accepted practices. Well-known industry accepted methods and practices recognize "as-found" savings associated with early replacements based on program designs that motivate customers to replace operating inefficient equipment with higher efficiency equipment prior to the end of life of the old equipment. One example of a document process for recognizing and quantifying "as-found" savings is the TRM/Mid-Atlantic Technical Reference Manual.

Witness Williamson also understates the extent to which the Companies' existing, accepted EM&V results appropriately recognize "as-found" impacts. While, as pointed out, EM&V for measures without an efficiency baseline recognize "as-found" savings, so do other accepted EM&V results for measures with efficiency baselines that utilize a consumption analysis. For example, DEC's Income Qualified Weatherization program assesses the impact of Tier Two measures, which include both HVAC and insulation, through a consumption analysis by comparing consumption of the treated participant group being evaluated against the consumption of a comparison group. Essentially, energy consumption when the old inefficient HVAC unit was being used is compared to energy usage after the new HVAC is installed. Consequently, the "as-found" methodology recognizes the actual system benefits that are being realized from the energy savings associated with the customer's participation in the program.

Q. PLEASE RESPOND TO THE PUBLIC STAFF'S RECOMMENDATION THAT THE COMMISSION DISTINGUISH ENERGY SAVINGS USED FOR EE/DSM COST RECOVERY PURPOSES FROM THOSE USED FOR CARBON PLAN COMPLIANCE.

A. The Companies struggle to understand the logic of the Public Staff's proposal to arbitrarily isolate energy savings from EE/DSM Programs reflected in the Carbon Plan from those recognized and used in the cost recovery for the EE/DSM Programs. If reduced carbon emissions associated with energy savings derived from utility EE programs is a value or utility system benefit (reducing the need for supply side investments needed to reduce carbon emissions), not recognizing the energy savings benefit in the cost effectiveness justification for offering EE programs under the Mechanism is a problematic disconnect. For example, if the Companies design a program to achieve energy savings associated with early replacement of an inefficient appliance and develop a higher incentive level based on cost effectiveness thru the recognition of "as-found" savings, they should be able to recognize the higher incentive cost associated with utilizing the "as-found" methodology. To recognize the higher incentive cost, while ignoring the higher energy savings and the associated system benefit, will yield a program that is not cost effective and should not be offered under the Mechanism. The Mechanism has a demonstrated record of accomplishment of effectively motivating the Companies to develop and offer customers EE and demand response programs that will deliver as much energy and capacity savings as cost-effectively as possible. The high level of EE program performance that the Companies have achieved through the Mechanism have been enabled by the Mechanism's alignment of cost effectiveness test results and the utility Portfolio Performance Incentives ("PPI"). The PPI appropriately reflects the recognized utility system benefits and costs associated with the energy savings achieved by the programs. If the Commission were to adopt the Public Staff's recommendation and sever this alignment, the goal of achieving as much cost-effective energy efficiency savings as possible will be significantly eroded. As this Commission has previously recognized, Senate Bill 3 provided that the utilities should be compensated for their DSM/EE efforts and allowed awarding of incentives, including rewards based upon shared savings and avoided costs achieved by DSM/EE measures.

III. RESPONSE TO AGO

Q. PLEASE RESPOND TO WITNESS BURGESS' COMMENT THAT COMMERCIAL AND INDUSTRIAL ("C&I") CUSTOMERS WOULD OPT IN IF OFFERED MORE ATTRACTIVE EE/DSM PROGRAMS.

A Witness Burgess comments that "[i]f Duke were to offer EE/DSM programs that were actually attractive to C&I customers, then there is the possibility that these customers would opt back in as a means to reduce their energy bills over the long run[,]"[1] without providing a basis for this contention that the Companies' programs are not attractive or describing in what ways they are lacking. The Companies have a long history of working with stakeholders in the DSM/EE Collaborative to ensure that their portfolios of non-residential programs are both attractive and comprehensive. The Companies' portfolios offer customer prescriptive incentives associated with over 440 unique energy efficiency measures, as well as two approaches to a custom non-residential program. The first approach, in the Performance Incentive Program is designed to cover less certain customer performance-based projects, like retro-commission and energy management system installations. The second approach, the Custom Incentives offered under the Energy Efficient Products and Assessment Program, is designed to allow

[1] AGO Burgess Direct Testimony at 83.

customers to receive incentives for specific complex efficiency projects where the savings are based on equipment and process efficiencies.

Witness Burgess also seems unaware that the Companies have made a number of changes to make opting in more attractive, such as developing separate EE and DSM Rider components to allow customers to opt into only paying for the portion of the non-residential programs that they participate in. DEC has also developed an additional opt in window in response to customer feedback that more time was necessary to understand their annual capital budgets that can be spent on an efficiency upgrade.

Q. PLEASE RESPOND TO WITNESS BURGESS' CRITICISM OF THE "AS-FOUND" BASELINE METHODOLOGY.

A. The Companies disagree with Witness Burgess' contention that an "as-found" baseline methodology would "erroneously compare the energy consumption of the newly purchased appliance to that of the broken one being replaced (*i.e.*, the "as found" appliance)."[2] As explained in the Companies' direct testimony, the enabler of recognizing an "as-found" baseline is not a blanket request for approval to utilize an "as-found" baseline for all EE/DSM programs. The identification of the "as-found" enabler was instead intended to demonstrate the Companies' recognition that to achieve higher levels of energy efficiency savings, or to reach beyond the low-hanging fruit, the Companies needed to seek approval of programs

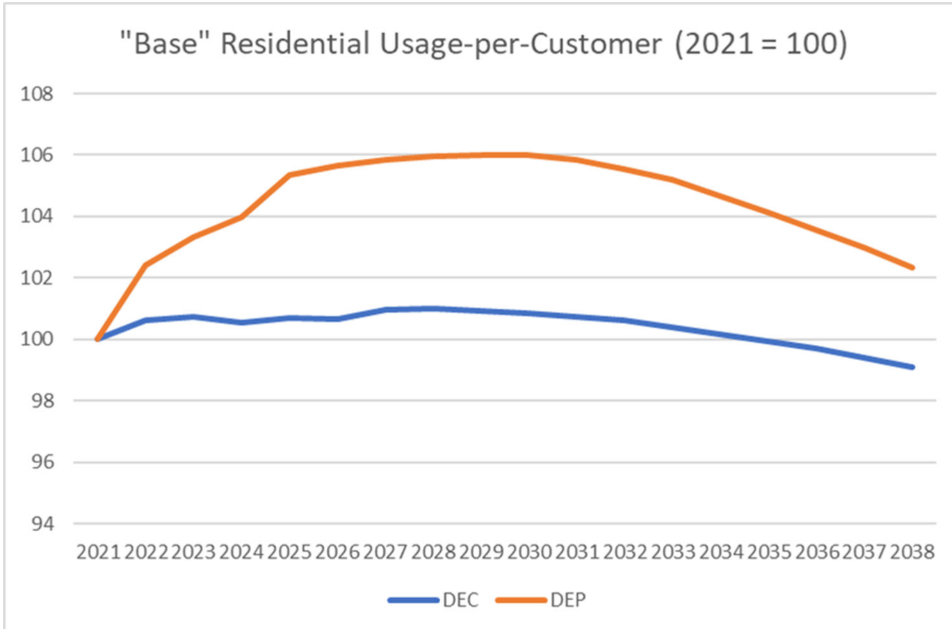
[2] *Id.* at 92.

and modifications to existing programs that promote early replacement of inefficient technologies by recognizing the resulting "as-found" savings.

Q. WITNESS BURGESS CONTENDS THAT THE COMPANIES' UTILITY ENERGY EFFICIENCY ("UEE") ROLLOFF FORECAST IS INACCURATE. HOW DO YOU RESPOND?

A. Witness Burgess provides no formal analysis for his contention that the Companies' UEE roll-off forecast is inaccurate. His contention appears to be solely based on the high-level observation that "Base" usage per customer (prior to factoring in UEE and electric vehicle adoption) is increasing in the near term before declining. As shown in Table 1 below, the "base" load forecast does include a moderate increase in residential usage per customer before starting to decline toward the end of the decade; however, one must look at the drivers to understand whether this is an accurate forecast or reflective of an underlying error related to UEE roll-off. Considering that the forecast appropriately reflects the load growing due to adoption of internet of things devices and a portfolio of EE programs (with an average measure life of over 8 years) a great deal of the EE roll-off from adoption of UEE programs will not occur until the latter half of the 2020s. Rather than contending the UEE roll-off included in the load forecast is in error, witness Burgess should see that the underlying assumptions have been appropriately reflected in the "base" load forecast.

Table 1. Base Residential Usage per Customer



IV. RESPONSE TO APPALACHIAN VOICES

Q. **DO YOU AGREE WITH WITNESS MCILMOIL'S CLAIM THAT THE COMPANIES' PROGRAMS TARGETING LOW-INCOME CUSTOMERS ARE "STARKLY UNDERFUNDED"?**

A. No. The Companies agree that developing new programs to more effectively target low-income customers and increase participation in their existing low-income programs is very important. However, the Companies disagree that program funding levels are a barrier to achieving this shared goal. The Companies' projected budgets and funding levels included in the Companies' annual EE/DSM Rider filings are in no way intended to be, nor do they act, as a cap on annual funding for the programs. Budgets are intended to be an accurate estimate of upcoming spending for the purposes of cost recovery. If, however, actual program participation exceeds the projections underlying the budget, the Companies will adjust their requested recovery as part of the reconciliation included in a future EE/DSM Rider filing.

Q. PLEASE RESPOND TO WITNESS MCIIMOIL'S CONTENTION THAT FUNDING AND PARTICIPATION SHORTFALLS IN EXISTING EE PROGRAMS MUST BE ADDRESSED BEFORE CONSIDERATION OF ANY PROPOSAL TO EXPAND THE ELIGIBILITY FOR LOW-INCOME EE PROGRAMS.

A. The Companies' proposed enabler expanding the definition of low-income to 300% of the federal poverty guideline was in no way envisioned to shift funding from the existing income eligible participants, but rather it was identified as a way to recognize that a larger pool of eligible customers would, if approved by the Commission in future program filings, allow for more customer participation and more energy efficiency savings.

V. RESPONSE TO CIGFUR

Q. MR. HUBER, CIGFUR WITNESS GORMAN ASSERTS THAT THE COMPANIES FAILED TO CONSIDER NON-RESIDENTIAL FLEXIBLE LOAD. DID THE COMPANIES CONSIDER ADDITIONAL DEMAND RESPONSE AND RATES FOR PRICE RESPONSIVE LOADS FOR NON-RESIDENTIAL CUSTOMERS IN ITS CARBON PLAN?

A. Yes. In fact, the Companies included several hundred megawatts of price-responsive loads in the Companies' Carbon Plan, consistent with the Comprehensive Rate Design Study Roadmap filed with the Commission in March 2022. Additionally, the Companies engaged CIGFUR members on multiple occasions to discuss demand response program options, including programs similar to the Southern California Edison program referenced by CIGFUR. The Companies plan to propose expansions to both demand response and dynamic pricing rates that will create load responsiveness supportive of both customer cost management and the Carbon Plan.

Q. WITNESS GORMAN ALSO CRITICIZES THE COMPANIES FOR NOT PROPOSING NEW CUSTOMER RENEWABLE PROGRAMS. CAN YOU COMMENT ON ANY UPDATED PLANS TO ADDRESS CUSTOMER RENEWABLE PROGRAMS?

A. Yes. Witness Gorman alleges that the Companies fail to leverage the customer renewable programs, but he omits that CIGFUR has been involved in extensive stakeholder efforts to develop such programs. As noted in a letter filed in this docket by the Companies on September 7, 2022, the Companies intend to continue to engage stakeholders on a comprehensive suite of programs at the conclusion of the Carbon Plan evidentiary hearing. In the meantime, and specifically in response to a CIGFUR recommendation made in its comments in this Docket,[3] the Companies will, in the near future, file for Commission approval of a "GSA bridge" of 250 MW (using the eligibility criteria for existing Green Source Advantage ("GSA") program) to satisfy customer demand until such time as new customer renewable programs can be proposed, with stakeholder input, and approved by the Commission.

VI. <u>RESPONSE TO NC WARN</u>

Q. NC WARN WITNESS POWERS ASSERTS THAT "THE NEM SOLAR ADDITIONS FORECAST IN THE 2020 IRP'S WERE MADE IN THE CONTEXT OF THE COMPANIES MODIFYING THE NEM TARIFF TO REDUCE BILL SAVINGS."[4] IS THAT ACCURATE?

A. No. The NEM forecast included in the 2020 IRPs were completed in the context of supporting the IRP as can be explained further by Duke Energy witness Kalemba on the Modeling and Near-Term Actions Panel.

[3] CIGFUR Comments at 28-29.
[4] NC WARN Powers Direct Testimony at 57.

Q. WITNESS POWERS STATES THAT THE "CARBON PLAN REDUCES THE ROLE OF NEM SOLAR DRAMATICALLY, RELATIVE TO THE 2020 IRP FORECASTS."[5] DO YOU AGREE WITH THIS ASSERTION?

A. No. As witness Kalemba discusses in his direct testimony,[6] the NEM forecasts in both the 2020 IRP and the Carbon Plan are based upon current inputs and policies approved at that point in time the forecasts are modeled. The difference between the forecasts is because the rooftop solar market is dynamic and changes in panel prices, historic adoption trends, average system size, etc. must be incorporated to make the forecasts as accurate as possible. Neither forecast incorporates the impact of proposed changes to net metering, the Smart $aver Solar proposed incentives, or the impact of the Inflation Reduction Act of 2022, as none of these policies were approved at the time the models were run.

VII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

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[5] *Id.*
[6] *See* Modeling and Near-Term Actions Panel, Direct Testimony at 124-125.

Duke Energy Carolina, LLC and Duke Energy Progress, LLC
Summary of Rebuttal Testimony – Grid Edge Panel
Lon Huber and Tim Duff
Carolinas Carbon Plan
Docket No. E-100, Sub 179

Our rebuttal testimony specifically responds to testimony filed by Public Staff witness David Williamson, the Attorney General Office's witness Edward Burgess, Appalachian Voices' witness Rory McIlmoil, CIGFUR's witness Michael Gorman, and NC WARN's witness William Powers.

The following provides an overview of the Companies' response to each of these witnesses' testimony:

- Public Staff Witness Williamson: The Companies disagree with witness Williamson's testimony that the demand-side management ("DSM")/Energy Efficiency ("EE") mechanism ("Mechanism") needs to be reopened to make the Companies' proposed updates. The Companies believe that the targeted required modifications to certain inputs to the Mechanism can be approved by the Commission without the need to reopen the Mechanism in its entirety. The Companies also believe that witness Williamson's recommendation with respect to the "as-found" baseline is overly broad and fails to recognize the link between "as-found" savings and programs that promote early replacement of measures. The Panel's rebuttal testimony also argues that witness Williamson understates the extent to which the Companies' existing, accepted evaluation, measurement, and verification results appropriately recognize "as-found" impacts.

- Attorney General Witness Burgess: The Companies disagree with witness Burgess' position regarding the attractiveness of the Companies' EE/DSM programs for commercial and industrial customers by explaining the Companies' ongoing engagement with the DSM/EE Collaborative to improve EE/DSM programs and by noting witness Burgess' failure to offer any specific programmatic enhancements or to acknowledge the number of changes the Companies have made to make these programs more attractive. The Companies also rebut witness Burgess' assertions regarding the Companies' utility energy efficiency roll-off forecast.

- Appalachian Voices Witness McIlmoil: This Panel's rebuttal testimony clarifies that, contrary to witness McIlmoil's testimony that funding levels are a "barrier", the projected budgets and funding levels included in the Companies' annual EE/DSM Rider filings are no way intended to be, nor do they act as, a cap on annual funding for the programs.

- CIGFUR Witness Gorman: This Panel's rebuttal testimony explains how the Companies considered additional demand response and rates for price responsive loads for non-residential customers in its Carbon Plan, contrary to witness Gorman's assertion that the Companies failed to consider non-residential flexible load. The Companies also explain that they look forward to continuing stakeholder engagement on a comprehensive suite of new customer renewable programs after the conclusion of the Carbon Plan evidentiary hearing.

- NC WARN witness Powers: This Panel's rebuttal testimony addresses inaccuracies in witness Powers' testimony regarding net energy metering.

This concludes our summary.

MS. FENTRESS: Thank you. The panel is now available for questions from the parties and the Commission.

CHAIR MITCHELL: All right. Let's see. Attorney General?

MS. FORCE: No questions.

CHAIR MITCHELL: Okay. Appalachian Voices, go ahead.

MS. CRALLE JONES: Good afternoon, Commissioners and Chair Mitchell and panel.

CROSS EXAMINATION BY MS. CRALLE JONES:

Q. My name is Cathy Cralle Jones, again, here before you on behalf of Appalachian Voices. And in your rebuttal testimony, you provided some specific responses to issues raised by Appalachian Voices. And I'd like to turn your attention to page 12 of your testimony, line 7.

A. (Tim Duff) Yes.

Q. And there you indicated that developing new programs to more effectively target low-income customers and increase participation in their existing low-income programs is very important, correct?

A. Yes.

Q. And then you go on to say that you disagree that program funding levels are a barrier to achieve this goal, correct?

A. Yes. The program budgets and funding are not the barrier.

Q. Okay. So I just want to ask you a couple of questions about current programs and funding levels.

Do you have a copy of the Carbon Plan Appendix G with you?

A. Let me see.

(Witness peruses document.)

Yes, I do.

Q. If you, please, would turn to pages 28 and 29.

A. I'm there.

Q. And Figures G-6 and G-7 generally show summer and winter demands and peaks and then discusses the higher peak load typically generated by low-income customers; is that fair?

A. Subject to check. I don't have time to read it. I do see that it calls out the different load shapes for the different --

Q. Okay. And then specifically looking at the very last sentence at the bottom of page 28, you'd agree with that conclusion, wouldn't you, that the partnership and engagement with low-income customers and advocacy groups will be critical for addressing this load?

A. Yes. We've long thought that, and we've long engaged with the low-income community weatherization agencies as well as other broad stakeholder groups that are interested in representing the interests of low-income customers.

Q. And so now if you would, turn back to page 6 of that where you list, in Table G-1, all of the current residential energy efficiency programs.

A. (Witness peruses document.)

I'm almost there. Sorry about that.

Q. No worries. Page 6.

A. Okay. There it is. Yup, I see it.

Q. Okay. And there you've got listed the residential programs. And focusing on low-income or income-qualified programs, the only targeted program listed in that table is the low-income weatherization program, correct?

A. No. There are two programs that are specifically targeted at reaching low-income customers and income-qualified customers, the neighborhood energy saver program and the low-income weatherization program. But as I -- as we talked about during my direct testimony, many of our mass market programs also effectively reach those customers.

Q. But the neighborhood energy saver program, that is not limited to income-qualified customers, correct?

A. Yes and no. It targets income-qualified customers because it targets neighborhoods where greater than 50 percent of the homes in that neighborhood or geographic area are at or below 200 percent of the federal poverty guideline.

Q. Remind me, I think that program, though, doesn't include all residential customers, correct? Doesn't it exclude mobile homes?

A. It currently does not, I believe, allow those manufactured homes, that's correct.

Q. And does it also exclude rental homes?

A. I don't believe it excludes rental premises, because it does cover -- it can cover multifamily rental premises.

Q. But if a person rents their home, unless the owner agrees, that's not a program open to renters?

A. Yes. We can't make modifications to a customer's home without the owner of the residence agreeing to those modifications.

Q. Now, you talked about modifications under the neighborhood energy saver program.

I've seen on the website that that's listed as $180 value; does that sound correct?

A. So you're -- I think you're talking about the tier 1 program, in terms of the measures that are directly installed according to the program. But we -- unfortunately, during COVID, we -- right before COVID we had implemented a change to that program to include much greater-valued measures and deeper energy efficiency saving measures, and it was targeting participants in the low-income neighborhood energy saver program that had higher energy usage. So if they had higher energy usage, they qualify for more expensive measures.

But with respect to the $180, that was the value associated with the direct install measures that were under the exist- -- the original tier. Like I said, unfortunately, because of COVID, we haven't had a ton of opportunity to get participation in that, because we have seen a real barrier to getting into customers' homes because of concern about the pandemic.

Q. The website indicates that there's $30 worth of free stuff; do you disagree?

A. So I think -- when you say "free stuff," I think you're talking about the measures of value versus the person going in and installing and auditing the premise.

Q. And that stuff includes LED bulbs?

A. There were some specialty LED bulbs, I believe, still included in that program, yes.

Q. And a low-flow shower head?

A. I believe that's one of the measures, yes.

Q. And then switch and outlet seals?

A. I think that's correct, yes.

Q. Okay. For a moment, then, let's go back and focus on the program that is listed here as low-income weatherization. Taking a cue from Commissioner Clodfelter during your direct testimony, I checked out the Duke website and wanted to take a minute to talk about that program.

It appears, based on the website information, that the program is conducted in partnership with the North Carolina Community Action Association, correct?

A. That's correct.

Q. In fact, the Duke website refers inquiries to the NCCAA website to determine eligibility, correct?

A. That's correct. They help Duke administer the program.

Q. Do you know what the current funding is for that program and how many low-income customers it serves?

A. I can't tell you how many have participated this year or what has been spent this year. I can tell you that I do recognize there have been some challenges, again, getting participation in that program, again, due to workforce issues, finding the actual labor to do it. But that's not unique to that program, we've struggled with other programs to get the necessary workforce to do the energy efficiency audits for some of the other programs and get into customers' homes.

And I also think it's important to note that the supply chain issues and the availability of equipment have also impacted that program, has been what I've been told. So yes, I think our participation is lower than what was originally projected, but I think that's been something that we've been dealing with in the post-COVID world across not only our neighborhood energy saver low-income weatherization program, but all the other programs.

Q. It's late in the afternoon and I'm trying to ask pretty direct questions.

So would you agree with me, or do you have any reason to disagree with the information on the website that says approximately $5 million will be provided annually for this program, and over 1,600 customers are expected to participate?

A. That's -- that's, I believe, the targets, yes.

Q. And that program is only available in the DEC territory, correct?

A. As I discussed with you specifically in my direct testimony, we filed for the expansion of that program in June to the DEP, the service territory. But yes, it is currently only available in DEC.

Q. Thank you. And we discussed earlier during your direct testimony and the Appalachian Voices Exhibit 3 that DEC has approximately 580,000 low-income customers.

Would you accept that, subject to check?

A. Subject to check.

Q. Okay. So if 1 percent of DEC low-income customers participated in the weatherization program, that would be 5,800 customers; does that lawyer math

make sense to you?
A. Yeah. Subject to check, I think that's pretty accurate.
Q. But the website says that there's only 1,600 that were expected to participate in the program.
So under the existing program, that would be less than one-third of 1 percent, correct?
A. So that -- I think your math is correct. I think it's important to note, though, that a lot of the limitations on participation are not associated with the funding that you referenced; it's due to what the -- we can get done through the actions agencies and that collaboration.
Q. We can disagree about the reasons for it, but the question for you, is reaching less than three-tenths of a percent of low-income customers for weatherization, is that a target that Duke's satisfied with?
A. It's a target that we believe was accurate at the time it was put on the website. We have been working with the low-income and affordability collaborative, including stakeholders like App Voices, to try and identify ways to approve the effectiveness and the reach of those programs. But as I said, some

of the program administration issues associated with that are not directly within Duke's control.

Q. Okay. And you mentioned before that you've applied to expand that program to DEP.

Will that 0.3 percent be a target that Duke would find acceptable in the DEP area as well?

A. I can't speak to what percentage it is without having the numbers in front of me. I can tell you we tried to put in realistic projections with respect to knowing what's going on in the market and knowing the issues we've seen with the DEC program, the participation that we think we can accurately get. Again, to inflate projections would only serve to artificially increase the rider without justification.

Q. And I guess whether it's projections and rider or if it's a target, a program goal, and I think that was my question, is that an acceptable target for Duke point --

A. So I don't think you can delineate the two. We use the program budgets. But as I mentioned, really -- I tried to mention a number of times, the Company is not capped by its targets or its budgets that it puts in its rider filing. Those we use for planning purposes, for cost recovery purposes to try and let people know what we think we can achieve. It's not a cap. We're not trying to leave low-income impacts on the table.

If we can get the participation, given some of the constraints that I've talked about, the Company would love to get the participation. It's not a matter of the budget providing a cap on what can be done or the target being a cap. We're putting that out there to communicate what realistically we think can be done as well as make sure that what we're seeking in cost recovery is appropriate and not inflated.

Q. Table G-1 lists -- we've talked about the low-income weatherization program, but it doesn't include other targeted low-income programs. But the helping home fund is another program listed on a Duke web page when you search income-qualified services.

Is the helping home fund a program -- an existing program in the DEP service area?

A. I don't believe it is. But the helping home fund is not an energy efficiency program, so I'm gonna be limited in what I can talk to about the helping home fund. The helping home fund is not something that is a part of the Commission-approved EE monies. So it's outside of the scope of really what I can testify to.

Q. Okay. Let me let me offer the website description of it and see if you disagree. The website --

MS. FENTRESS: Objection. I believe that Mr. Duff has explained that he is not knowledgeable about this. The helping home fund is not part of our EE portfolio. It is funded through shareholder dollars and has been the result of mergers and rate cases in the past. It is not within the purview of Mr. Duff's rebuttal testimony.

CHAIR MITCHELL: Ms. Cralle Jones?

MS. CRALLE JONES: Commissioner Clodfelter, I believe, had asked about if I wanted to find where these low-income programs were, where would I look on the website. I checked the website. The website says income-qualified services. And that is -- includes the helping home fund, which the website describes as "Income-qualified North Carolina families will save energy and money through free home energy makeovers provided by Duke energy's helping home fund. Households will receive energy saving upgrades through a $2.5 million" --

CHAIR MITCHELL: All right. Ms. Cralle Jones, what's your question, though? I mean, why are you asking this witness the question?

MS. CRALLE JONES: Again, to see, kind of, the targets of who is being reached by these programs.

CHAIR MITCHELL: Okay. I'm gonna sustain the objection because Mr. Duff has indicated that that particular program is not within the scope of the programs that he's -- with which he's familiar.

MS. FENTRESS: Okay.

COMMISSIONER CLODFELTER: Chair, just so the record is clear, the question I asked Mr. Duff was not about low-income programs, it was about the integrated grid solution retail products.

CHAIR MITCHELL: All right. Please proceed, Ms. Cralle Jones.

Q. So on page 9 and 10 of Exhibit G that we talked about, the Company lists the planned and proposed EE programs. And in your rebuttal testimony, and you've said today that those program funding levels are not a barrier to reaching the shared goal of more targeted investments for low-income customers and increase their participation. And based upon what we've talked about, we've got a current allocation of $5 million for the weatherization fund.

Is that an annual allocation fund?

A. So it's the -- I think it's the projected annual budget associated with the program that's approved.

Q. Okay. And has Duke determined how many more customers, in at least DEC, would fall into the 200 percent to 300 percent range of low-income customers?

A. I don't have -- we didn't do that analysis, specifically. The issue with that analysis is it fluctuates. It's a point in time, and so it's a little bit of a challenge to do that, as well as it's tied to residence, and residence changes over time. But it's something that we -- that we can do at a point in time, but we did not do that specific analysis.

Q. And I would assume, then, that you haven't done the analysis for DEP to figure out how many additional low-income customers would be included in that mix if the goal were expanded to 300,000?

A. No. As I said before, the proposal to potentially increase the income qualification for certain new low-income programs would just expand that pool of customers that would be eligible for low-income programs.

As I said, with those income-qualified programs, obviously we would want to make that eligibility change as part of a program filing, and we would have participation projections at the time that we would be seeking approval of that. As well as the cost-effectiveness, which as I mentioned before, is something we'd would want the Commission to consider, since income-qualified programs tend not to be cost-effective.

Q. Have the Companies considered just setting a goal for energy efficiency programs designed for and delivered to low-income customers as part of shrinking the challenge, just saying we will reach X percentage as a goal?

A. I don't think -- we don't think that that's necessarily an accurate approach to do things. Like I said, income qualifications can change that would qualify customers' eligibility. And as I also talked about before, it's important to remember that we have a whole portfolio of programs that can help those customers achieve savings.

And so to put specific targets associated with a segment of customers is something that would likely be somewhat of a distraction from the overall goal, which is to get as much cost-effective energy efficiency, and in the case of the Carbon Plan and factoring in income-qualified programs, as much energy efficiency as possible.

We don't think you need a -- we don't think you need a target, because the target is to do as much as we can.

Q. We talked earlier about the American Council for Energy Efficient Economy and their scorecard and where DEC and DEP fell into that scorecard. And I haven't had a chance to review in detail, but it appears that part of your late-filed exhibit goes into some explanation about that.

Can we agree that there are utilities and regulatory bodies in other states that have implemented program goals and funding requirements that target energy efficiency programs for low-income customers?

A. I'm not specifically aware of any. None of the states that Duke operates in that I'm familiar with, we don't have those specific targets associated with achievements, other than what we have here in

North Carolina, which is a projected target as a part of the cost recovery filing and then annual reconciliations to that target.

Q. In follow-up to your direct testimony, Commissioner McKissick -- and I really did find this one in the transcript -- asked whether you could, quote, discretely identify what set of policies would really need to be adopted and what set of circumstances would be needed to get there. And that was, if needed for the record, on page 73 from the September 16th hearing.

Do you recall that exchange?

A. Yes, I do, because that was on the 16th, as you said, that was the cause for the late-filed exhibit that I thought was gonna take a lot more time. And I thought I had 30 days and found out I had 11. So yes, I definitely remember that conversation.

Q. Are you aware that ACEEE, the group that we've talked about before, has put together a guide for regulators supporting low-income energy efficiency?

A. Not specifically, no.

Q. Okay.

CHAIR MITCHELL: All right.

Ms. Cralle Jones, I'm gonna stop you there. We've come to the end of the day. We will be back in the morning. Let's go off the record. We'll be back in the morning at 9:30. And we will resume with Ms. Cralle Jones' examination of the panel.

(The hearing was adjourned at 4:59 p.m. and set to reconvene at 9:30 a.m. on Thursday, September 29, 2022.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

I, Joann Bunze, RPR, the officer before whom the foregoing hearing was conducted, do hereby certify that any witnesses whose testimony may appear in the foregoing hearing were duly sworn; that the foregoing proceedings were taken by me to the best of my ability and thereafter reduced to typewritten format under my direction; that I am neither counsel for, related to, nor employed by any of the parties to the action in which this hearing was taken, and further that I am not a relative or employee of any attorney or counsel employed by the parties thereto, nor financially or otherwise interested in the outcome of the action.

This the 2nd day of October, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112