PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, September 19, 2022

TIME: 1:46 p.m. - 5:00 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: 16

Noteworthy Reporting Services, LLC

A P P E A R A N C E S:

FOR DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC:

Jack E. Jirak, Esq., Deputy General Counsel
Kendrick C. Fentress, Esq., Associate General Counsel
Jason A. Higginbotham, Esq., Associate General Counsel
Kathleen Hunter-Richard, Esq.
Duke Energy Corporation
Post Office Box 1551
Raleigh, North Carolina 27602

Andrea Kells, Esq.
E. Brett Breitschwerdt, Esq., Partner
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

Vishwa B. Link, Esq., Partner
McGuireWoods LLP
Gateway Plaza
800 East Canal Street
Richmond, Virginia 23219-3916

A P P E A R A N C E S Cont'd.:

Lara S. Nichols, Vice President,
State & Federal Regulatory Legal
Duke Energy Corporation
4720 Piedmont Row Drive
Charlotte, North Carolina 28210

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Taylor Jones, Esq., Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, and THE SIERRA CLUB:

Gudrun Thompson, Esq., Senior Attorney
David, L. Neal, Esq., Senior Attorney
Nicholas Jimenez, Esq., Senior Attorney
Southern Environmental Law Center
200 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

A P P E A R A N C E S Cont'd.:

CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Christina D. Cress, Esq., Partner
Douglas E. Conant, Esq., Associate
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

FOR CAROLINA UTILITY CUSTOMER ASSOCIATION and FOR TECH CUSTOMERS:

Matthew B. Tynan, Esq.
Brooks Pierce
Post Office 26000
Greensboro, North Carolina 27420

Craig Schauer, Esq.
Brooks Pierce
1700 Wells Fargo Capitol Center
150 Fayetteville Street
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:
John D. Burns, Esq., General Counsel
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

FOR BRAD ROUSE:
Brad Rouse, Pro se
Brad Rouse Consulting
3 Stegall Lane
Asheville, North Carolina 28805

FOR CLEAN POWER SUPPLIERS ASSOCIATION:
Ben Snowden, Esq., Partner
Erin Catlett, Esq., Associate
Jack Taggart, Esq., Associate
Fox Rothschild LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

A P P E A R A N C E S Cont'd.:

FOR THE ENVIRONMENTAL WORKING GROUP:
Andrea C. Bonvecchio,Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

Carolina Leary, Esq.
1250 I Street Northwest, Suite 1000
Washington, DC 20005

FOR WALMART INC.:
Carrie H. Grundmann, Esq., Member
Spilman Thomas & Battle, PLLC
110 Oakwood Drive, Suite 500
Winston-Salem, North Carolina 27103

FOR CITY OF CHARLOTTE:
Karen Weatherly, Esq., Senior Assistant City Attorney
600 East Fourth Street
Charlotte, North Carolina 28202

A P P E A R A N C E S Cont'd.:

FOR APPALACHIAN VOICES:
Catherine Cralle Jones, Esq.
The Law Offices of F. Bryan Brice, Jr.
127 West Hargett Street, Suite 600
Raleigh, North Carolina 27601

FOR REDTAILED HAWK COLLECTIVE, ROBESON COUNTY COOPERATIVE FOR SUSTAINABLE DEVELOPMENT, ENVIRONMENTAL JUSTICE COMMUNITY ACTION NETWORK, and DOWN EAST ASH ENVIRONMENTAL AND SOCIAL JUSTICE COALITION:
Ethan Blumenthal, Esq.
ECB Holdings LLC
1624 Nandina Comers Alley
Charlotte, North Carolina 28205

FOR NC WARN and
FOR CHARLOTTE-MECKLENBURG NAACP:
Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

A P P E A R A N C E S Cont'd.:

FOR BROAD RIVER ENERGY, LLC:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

FOR KINGFISHER ENERGY HOLDINGS, LLC, and
FOR PERSON COUNTY, NORTH CAROLINA:
Patrick Buffkin, Esq.
Buffkin Law Office
3520 Apache Drive
Raleigh, North Carolina 27609

Kurt Olson, Esq.
The Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION:
Tim Dodge, Esq., Regulatory Counsel
3400 Sumner Boulevard
Raleigh, North Carolina 27616

A P P E A R A N C E S Cont'd.:

FOR THE CITY OF ASHEVILLE and COUNTY OF BUNCOMBE:

Jannice Ashley, Esq., Senior Assistant City Attorney
City Attorney's Office
70 Court Plaza
Asheville, North Carolina 28801

Curt Euler, Esq., Senior Attorney II
Buncombe County
200 College Street, Suite 100
Asheville, North Carolina 28801

FOR MAREC ACTION:

Bruce Burcat, Esq, Executive Director
MAREC Action
Post Office Box 385
Camden, Delaware 19934

Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

A P P E A R A N C E S Cont'd.:

FOR TOTALENERGIES RENEWABLES USA, LLC, and
FOR CLEAN ENERGY BUYERS ASSOCIATION:
Joseph W. Eason, Esq.
Nelson, Mullins, Riley & Scarborough LLP
4140 Parklake Avenue, Suite 200
Raleigh, North Carolina 27612

Weston Adams, Esq.
Nelson, Mullins, Riley & Scarborough LLP
1320 Main Street, Suite 1700
Columbia, South Carolina 29201

FOR PORK COUNCIL:
Kurt J. Olson, Esq.
Law Office of Kurt J. Olson, PLLC
Post Office Box 10031
Raleigh, North Carolina 27605

FOR COUNCIL OF CHURCHES:
James P. Longest, Jr., Esq.
Duke University School of Law
Box 90360
Durham, North Carolina 27708

A P P E A R A N C E S Cont'd.:

FOR AVANGRID RENEWABLES, LLC:
Benjamin Smith, Esq.
Todd S. Roessler, Esq.
Joseph S. Dowdy, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR SEAN LEWIS:
Sean Lewis, Pro se
640 Firebrick Drive
Cary, North Carolina 27519

FOR THE USING AND CONSUMING PUBLIC, THE STATE, AND ITS CITIZENS:
Margaret Force, Esq., Special Deputy Attorney General
Tirrill Moore, Esq., Assistant Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC:

Lucy Edmondson, Esq., Chief Counsel
Robert Josey, Esq.
Nadia L. Luhr, Esq.
Anne Keyworth, Esq.
William E.H. Creech, Esq.
William Freeman, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

P R O C E E D I N G S

CHAIR MITCHELL: Let's go back on the record, please. We are at redirect for the panel.

MS. NICHOLS: Sure. Just a few questions.

Whereupon,

NELSON PEELER AND LAURA BATEMAN,

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

REDIRECT EXAMINATION BY MS. NICHOLS:

Q. Mr. Peeler, do you recall Ms. Cress was asking you some questions regarding a response to the Public Staff data request regarding merging DEC and DEP?

A. (Nelson Peeler) Yes.

Q. Does the timeline showing a merger by beginning of 2027 in your Exhibit 1 give the Companies time to get further clarity on the alignment between North Carolina and South Carolina?

A. Yes, it does.

Q. And if we -- if the Companies are able to merge DEC and DEP by 2027, are the alternative methods for addressing rate differential between DEC and DEP needed?

A. No, I don't believe they are.
Q. Can you explain why?
A. There is very -- very minimal investment in the carbon -- related to the Carbon Plan between those time periods, and there's very little difference between investments in DEP and DEC during that time. So very little opportunity for additional rate disparity to occur.
Q. Thank you. Nothing further.
CHAIR MITCHELL: All right. We'll take questions from Commissioners. Commissioner Clodfelter. Okay. Commissioner Clodfelter.
EXAMINATION BY COMMISSIONER CLODFELTER:
Q. Ms. Bateman, you were asked a number of questions by counsel about the South Carolina IRP proceedings.
Are you familiar with the documents and the filings throughout the course of 2022 and the integrated resource plan proceedings in South Carolina?
A. (Laura Bateman) So I was not involved in those proceedings.
Q. You were not. How about you, Mr. Peeler?
A. (Nelson Peeler) No, sir.
Q. So if I wanted to ask you a question about

the portfolio that was ultimately adopted pursuant to directive by the South Carolina Public Service Commission, you would not be the person to ask that question about?

A. (Laura Bateman) I would -- if it gets into any details, I mean, I know it was called A-2.

Q. A-2.

A. But I think any details about that portfolio, I would address to the Modeling Panel.

Q. To the Modeling Panel?

A. They were definitely involved in that.

Q. Well, let me try with you and see.

A. Okay.

Q. Because if you do know the answer, that saves us time going down the road. If you don't, I'll ask them.

A. Sure.

Q. In Portfolio A-2, which is the one the Commission ultimately approved, it has that Marshall Units 1 through 4 would retire in 2035 and Belews Creek 1 and 2 would retire in 2039.

And my question, based on the summary materials that I've got, is I'm not sure whether those are still running as coal -- 100 percent coal units, or were they contemplated under that portfolio at some point to switch to predominantly gas units?

A. I would ask the Modeling Panel.

Q. Yeah, I'll ask the Modeling Panel. Thank you. That's all I have.

CHAIR MITCHELL: All right.

Commissioner Duffley.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. Good afternoon. So I had a clarification question about an exchange you had with Ms. Cress. And you mentioned the frameworks that were being developed by Appalachian Power and SWEPCO, and I just want to make sure I heard accurately what you were saying.

So in this allocation of costs between jurisdictions, as I understood it, the framework would -- if a certain jurisdiction paid for the plant, they'd get the full output of the plant. And then I heard that the allocation of system cost would be lower. And I just want to clarify.

So, for example, if North Carolina paid for a plant, they would receive full output of that plant, and then North Carolina's allocation of the system costs would be lower. So let's say 80/20, that 80 percent North Carolina through -- through accounting, y'all would somehow figure out the benefits and lower that 80 percent allocation factor; is that correct?

A. (Laura Bateman) Yeah. And so I was not -- for that I was not necessarily referencing how Appalachian Power or SWEPCO do it, for that I was talking about how we've been thinking about this. And so I think we would -- you'd have -- if there were a North Carolina-only resource, like let's say some amount of solar that was North Carolina-only. So the output from that solar would go directly to North Carolina retail; and then the allocation of the remaining system would be lower than it otherwise would be.

Now, things that we haven't worked through yet is that, based on marginal cost, do you have two separate stacks -- do you have a North Carolina stack and a South Carolina stack, and when you get to the top of the stack that's when you -- you know, is South Carolina buying from North Carolina at the top of the stack? And you have some marginal variable cost, marginal fuel and variable energy that transfer over, along with some amount of capacity cost that is associated with that generation at the top of the stack. So that would be one way to do it.

You could also do it based on embedded or average cost. So for the example, the 80/20, if, let's say, 5 percent of that 80 is served by the solar, then your allocation of the remaining costs, you just adjust the allocation factors, both in the fuel proceeding for that variable fuel cost and in the base rate case for the capacity piece of it. You know, that would be another way to think about it.

So -- so I think these are the kind of questions that we're wrestling with and that we need to figure out answers to. And then also I think we don't think South Carolina could just opt out of everything. You do need to build something to serve your gen- -- your load. And so what kind of parameters and limitations do we want to put on it.

So those are some of the questions that we still need to work through, and obviously we need input from Public Staff, ORS, this Commission, South Carolina Commission as we work through those issues.

Q. Okay. Thank you for that. And then my one other question is, on page 7, you're discussing that -- that a merge -- merging the Companies will result in a shift of cost responsibility from wholesale jurisdiction to retail jurisdiction. I don't remember seeing any numbers.

I'm just wondering, trying to get a baseline, how significant is this cost shift?

A. So not very significant.

Q. Or would it be?

A. Yeah, it's not very significant. We don't expect it to be very significant. But it comes from the fact that North Carolina retail for production, both demand and energy and production costs, generation costs is the majority of our costs. So those costs for North Carolina retail is about 67 percent of the DEC system, but only 62 percent of the DEP system.

So because North Carolina retail has a higher percentage of the lower cost system, and a lower percentage of the higher cost system, when you merge them together and allocate back out, there's a slightly higher average cost to the new North Carolina retail system.

So it's just that differential between 62 percent and 67 percent. We've run a couple of different things. Less than 1 percent impact on customer bills is what we would estimate.

Q. Okay. Thank you for that. No further

questions.

CHAIR MITCHELL: All right. Any additional questions? Do you have a question? Go ahead, Commissioner Hughes, and then Commissioner McKissick.

EXAMINATION BY COMMISSIONER HUGHES:

Q. I'm just curious about something. If you haven't done it, don't worry about it.

The -- have you talked about or calculated a weighted customer impact for South Carolina versus North Carolina, kind of taking into consideration the blend of how much -- how many customers are DEC versus DEP in both states? Does that question make sense?

A. So let me see if understand it correctly. Are you asking, kind of, the same question that Commissioner Duffley asked but what's the South Carolina retail impact?

Q. Yeah, for the average household.

A. Okay. So we have looked at, not necessarily split by customer class, but South Carolina retail for production costs is currently around 24 percent of the DEC system, but only 9 percent of the DEP system. So they have a bigger differential in those allocation factors. And so we would estimate their impact to be maybe 2 to 3 percent.

So it would be more significant than the impact on North Carolina retail coming from that merging the systems together and then reallocating back out.

Q. Okay.

CHAIR MITCHELL: All right.

Commissioner McKissick.

EXAMINATION BY COMMISSIONER McKISSICK:

Q. Just one or two quick questions, and it relates to the potential merger. And, of course, one of the goals is to minimize the rate differential between DEC and DEP. But I noticed in your testimony -- you addressed it somewhat earlier, Ms. Bateman -- the fact that there would be these legacy rates that would continue for some period of time.

Could you go into a little bit more detail about how you envision that occurring and over what period of time they would -- it would take to kind of minimize that -- or get it to the point where there's no longer this differential from legacy rates?

A. (Laura Bateman) Yeah, and so I think the high-level answer is I don't know. But it would be very much up to this Commission. And so I'll give the example of Nantahala Power, I believe the Public Staff witness McLaughlin referenced that as well.

So Duke power and Nantahala Power & Light merged, I think it was maybe early 2000s. And then over time, this Commission determined, you know, how quickly to move those rates closer together. And I think, in that example, it took 12 years, approximately. So that's one example. I gave the example of Florida Power & Light and Gulf Power, and they did that over five years. So a little bit more quickly.

I think that's something, in terms of the existing differential, you could merge that over whatever period of time made sense, given the other rate impacts in a particular rate case or a fuel proceeding. So that -- I think there's a lot of discretion there to move more quickly or less quickly.

But the one thing that it would do is for the new costs, the new increases, the Carbon Plan impacts, those would be allocated more proportionately between DEC and DEP.

Q. Well, that was gonna be the second part of my question. So that would be more proportional and they would go into effect almost immediately, I would assume?

A. Yeah.

Q. Okay. Well, that gives me a little bit more realistic idea of what kind of timeline might be involved.

A. Okay.

Q. Thank you.

CHAIR MITCHELL: All right. Any additional questions from Commissioners?

(No response.)

EXAMINATION BY CHAIR MITCHELL:

Q. Just a few questions for you-all. I want to make sure I'm entirely clear on -- in light of y'all's testimony, the way that the modeling was carried out.

Did the modeling assume two separate operations, DEP and DEC, or did it assume combined operations?

A. (Nelson Peeler) So the assumption in the modeling, it assumed consolidated system operation, so it assumed combining the transmission functions. It did not assume a single utility. So it still continued to assume two separate utilities.

Q. Okay. Two separate utilities but combined

transmission system?
A. Correct. So the big difference would be it combines the transmission system and the transmission functions, but still keeps separate a resource plan and unit commitment.
Q. Okay.
A. The merger would give you a single resource plan and unit commitment. That would be the main change in modeling.
Q. Okay. Just following up with you to make sure I'm completely clear.
So when you say "separate unit commitment," so each utility maintains its own generation portfolio and dispatch occurs from that portfolio for each of those utilities?
A. Correct. A lot like we do today.
Q. Okay.
A. It would be a separate commitment but a joint dispatch.
Q. Okay. And so we have the joint dispatch agreement in effect today, and so help me understand what the difference would be between the way operations are conducted today versus under the scenario that you-all modeled.

A. So the primary difference would be it would take away some transmission restrictions that we have today. So with two separate balancing areas, they each have to be balanced in real time separately.

Q. Okay.

A. And so with combining the balancing areas would let them be balanced as one in real time. So there would be a few constraints removed. Transmission constraints mostly. Otherwise, it's predominantly the way it's done today.

Q. Okay. Can you be more specific about transmission constraints? Just again, so I'm entirely clear on what you mean.

A. Sure. Today, with two separate balancing authorities, we have -- you know, the joint dispatch agreement that we have allows us to use non-firm transmission for that -- for that dispatch. We also have an as-available capacity sharing agreement that we use. Neither of those would be required if we went to one balancing authority, it would just be based on the physical limitations of the wires.

Q. Okay. Understood. So under the scenarios you modeled -- just make sure I understand it correctly -- it's a more dynamic environment versus the environment which you operate now, you have to operate pursuant to those two agreements, when your --

A. Yes.

Q. When there's an exchange between the two operating companies?

A. Yes, that's correct.

Q. Okay. And I realize I've probably really oversimplified that, but I'm just wanting to make sure I understand.

A. No, I think that's a good summary.

Q. Okay. Ms. Bateman, or either of y'all can answer. I think this is gonna go to you, though, Ms. Bateman.

When you discuss keeping rates below the national average in your testimony, what benchmark are we -- what are you benchmarking as the national average?

A. (Laura Bateman) So I was looking at the EEI data that's available and the national average that they calculate.

Q. Okay. All right. Thank you. I just want to ask a question or two about the discussion that's been ongoing about competing public policies, you know, between jurisdictions.

Do you-all pay attention to what's going on outside of North and South Carolina, specifically in other regions of the country or in other jurisdictions, just for purposes of maintaining your awareness?

A. I try to, to the extent I'm able.

Q. And I don't mean specifically with respect to Duke's operations, I just mean other utilities in other parts of the country.

A. (Nelson Peeler) Yes, to the extent possible.

Q. And other states as well.

Is it fair to say that competing public policies as -- insofar as utilities that operate either across jurisdictional boundaries or in the context of larger organized structures, competing public policies is an issue that -- that this country is grappling with anywhere and everywhere in the country?

A. (Laura Bateman) I would agree with that.

Q. Okay.

A. And I -- yeah.

Q. And so I recognize you've indicated that you-all are looking at SWEPCO and you're looking at Appalachian Power as examples of utilities that are wrestling with this issue, and by "this issue" I mean competing public policies.

Where -- whether it's an RTO or non-RTO jurisdictions, where else are competing public policies being married up effectively? Is there any example in the country that you can point to?

A. (Laura Bateman) So --

Q. And if the answer is no, the answer is no.

A. Well, I will just qualify with the effectively. So I think we're looking at -- I think a lot of utilities are grappling with it.

Q. So it's fair to say it's a challenge --

A. It's a challenge.

Q. -- that we're sorting through at this point in time?

A. It is a challenge. I know -- so some other examples, PacifiCorp operates in six different states and two balancing authorities. And so they've got some things that they're working through there.

Q. Can you be specific? What is PacifiCorp -- what are the issues that -- to the extent that you know, what is PacifiCorp working through?

A. I think the state of Washington has clean energy transformation -- the Clean Energy Transformation Act, and I don't know all the details on that. But I think there are some different policies in their different states, and so they're trying to work through that.

Q. Okay.

A. Uh-huh.

Q. Okay. And how many -- for how many years or for how many decades has -- have the Duke systems and sort of legacy Duke systems spanned two jurisdictions, spanned North and South Carolina?

A. A hundred years or more.

A. (Nelson Peeler) More than 100 years.

Q. Okay. And for the most part, has the Company managed the risk of operating in multiple jurisdictions for the -- to the benefit of its ratepayers and maintaining reliable system operations?

A. (Laura Bateman) Yes.

Q. Has it always been easy?

A. I wouldn't say it's always been easy.

Q. Okay. But the Company has navigated those challenges, and oftentimes legal questions that arise, have come to this Commission or the South Carolina Commission or to the courts; is that correct?

A. I would agree.

Q. Okay. Okay. Ms. Bateman, did I hear you say that you were hopeful about the future of the systems in North and South Carolina?

A. Yes.

Q. Okay. Mr. Peeler, I see you have a smile on your face. Does that mean you're hopeful too?

A. (Nelson Peeler) Absolutely.

Q. Okay. Okay. And, I mean, I'm not -- not to make light of the situation that this utility faces -- these utilities, I'm sorry -- but I just -- I'm just wanting to hear from you all that the Company has, in the past, navigated through jurisdictional issues and is actively engaged in doing so now?

A. (Laura Bateman) Absolutely.

Q. And I -- the Public Staff's testimony highlights the need, and the way I read it, expresses urgency, and pretty significant urgency, in terms of the Companies' need to get moving on addressing the disparity in rates or the disparity that could be exacerbated as we move forward with the Companies' execution of its resource plans.

And do you-all -- I've heard your testimony and I've read your testimony in the Carbon Plan indicating that you all are looking at options for addressing the allocation of costs and the -- sort of the managing the disparity that could arise or could be further exacerbated.

Are you-all -- can you help me understand -- sort of putting aside the issue of the merger that's gonna require multiple regulatory -- levels of regulatory approval, are you-all taking action right now to work on solutions that can be implemented as soon as costs associated with the execution of the Carbon Plan begin to be recovered from customers?

A. So I think I maybe have a slightly different perspective from the Public Staff, and I tried to articulate this in my rebuttal testimony. That if you look at the costs through 2026, the revenue requirements through 2026, you really don't see that much of a differential between DEP and DEC. And so in many of the portfolios, DEC actually has a higher revenue requirement per megawatt hour, in some it's DEP. But usually that differential is maybe $1 per megawatt hour. Yeah, $1 per megawatt hour or less.

Q. Can you -- just stopping you and interrupting you, and I apologize for that, but what does the mean for the customer? If we're talking about $1 per megawatt hour, how does that --

A. Yeah, and so --

Q. -- to the extent that you can roughly translate that.

A. Very, very roughly, because there might be some nuances in the allocation factors, but $1 per megawatt hour is $1 per 1,000 kilowatt hours.

Q. Okay.

A. So if you look at the typical residential bill --

Q. Okay. Got it.

A. -- about $1 or less.

Q. Okay.

A. If you get to 2030, if you look at some of the rate impacts that we provided, you can see as much as, in some of the portfolios, a $10 differential there. And so I think when you get to 2030, I see much more of a need to have a solution by then. But I don't see that in '24, '25, '26.

Q. Okay. Okay. All right. Let me check in. Thank you, Ms. Bateman and Mr. Peeler.

CHAIR MITCHELL: Any additional questions before we take questions on Commission's questions? Go ahead, Commissioner Duffley.

EXAMINATION BY COMMISSIONER DUFFLEY:

Q. So it's not a question, but it's -- when we get to rebuttal, you mentioned the $1 differential per megawatt hour. And that's in the P2 scenario. So I'm wanting to know, when we get to rebuttal, why that one seems so much higher than the others. The differential between the two Companies under the P2 version, it was larger than the other versions.

A. (Laura Bateman) By 2030?

Q. I think it was 2030. I don't have it in front of me, but --

A. Yeah, I can --

Q. -- just look into that.

A. -- speak to that.

Q. Thank you.

A. In the 2030 time frame, the portfolios that had the largest differential, it was due to offshore wind coming in service in 2029.

Q. Okay.

A. And so you get your highest year revenue requirement in 2030.

Q. Okay. Thank you.

CHAIR MITCHELL: All right. We'll take questions on Commissioners' questions. We will start over here, the intervenors. CIGFUR, do you have -- attorney -- okay. CIGFUR, do you have questions?

MS. CRESS: No. Thanks, Chair Mitchell.
CHAIR MITCHELL: All right. Who's next? Anybody -- go ahead. Public Staff.
EXAMINATION BY MS. EDMONDSON:
Q. One clarifying question.
When you were talking about less being allocated to North Carolina if South Carolina opted out of a generation, do you mean less energy would be allocated or less production plant also?
A. (Laura Bateman) Both.
A. (Nelson Peeler) Both.
Q. Okay. And one last question.
Why not go ahead and work on this allocation issue? Why are we waiting?
A. (Laura Bateman) Between DEC and DEP?
Q. Right.
A. Because we think the merger is the best way to address that. If you look at some of the other alternatives that I gave, if we're not able to achieve a merger, they're complicated and could add more cost to customers.
So specifically that transmission issue, we might end up building a more costly system. If we have to build more firm transmission in order to have DEC

own more of the generation if we are not able to achieve the merger.

Q. All right. Thank you.

MS. NICHOLS: No questions.

CHAIR MITCHELL: All right. With that, then, you-all may step down. Thank you very much for your testimony today. And I'll take motions from the parties.

MS. NICHOLS: Sure. I'll move the panel's Exhibit Number 1. And then does the Commission also want for us to move their summary --

CHAIR MITCHELL: Yes.

MS. NICHOLS: -- that was prefiled? So I'd move their summary into evidence as well.

CHAIR MITCHELL: Hearing no objection to that motion, the exhibit to the witnesses' testimony will be accepted into evidence. And we will also accept into evidence as if copied -- copy into the record as if given orally from the stand, the witness testimony summary.

(Carolinas Utilities Operations Panel Exhibit 1 was admitted into evidence.)

(Whereupon, the prefiled summary

testimony of the Carolinas Utilities Operations Panel was copied into the record as if given orally from the stand in Volume 15 at the time their prefiled direct testimony was entered.)

CHAIR MITCHELL: All right. Go ahead CIGFUR.

MS. CRESS: Chair Mitchell, at this time, CIGFUR II and III would request that CIGFUR II and III's Carolinas Utilities Operations Panel Direct Cross Examination Exhibits 1 through 9 be admitted into the record.

CHAIR MITCHELL: All right. Motion --

MS. NICHOLS: And we'll -- objection to Cross Examination Exhibit Number 3, the typical bill calculations exhibit that there wasn't a foundation for.

CHAIR MITCHELL: All right. I will note the objection, but I'm gonna overrule it and we're gonna allow the exhibits into evidence.

(CIGFUR II and III Carolinas Utilities Operations Panel Direct Cross Examination Exhibits 1 through 9 were admitted into evidence.)

MS. CRESS: Thank you, Chair Mitchell.

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

MR. JIRAK: Thank you. If we may have just about one minute here to get organized. Thank you.

MS. KELLS: Good afternoon. Andrea Kills for Duke Energy. The Companies call the Transmission Panel.

CHAIR MITCHELL: All right. Good afternoon. If you would raise your right hands, please. Left hand on the Bible.

Whereupon,

SAMMY ROBERTS AND MAURA FARVER,

having first been duly sworn, was examined

and testified as follows:

CHAIR MITCHELL: All right.

DIRECT EXAMINATION BY MS. KELLS:

Q. All right. I'll start with Mr. Roberts.

Would you please state your full name and business address for the record?

A. (Sammy Roberts) Yes. My name is Dewey S. Roberts, II. I go by Sammy. And my address is 3401 Hillsboro Street, Raleigh, North Carolina.

Q. And by whom are you employed and in what capacity?

A. I'm employed by Duke Energy as general manager of transmission planning and operations strategy.

Q. And can you please briefly describe your role and responsibilities at Duke Energy?

A. Yes. I have a primary responsibility for the development of midterm and long-term strategy for transmission planning and operations. And that includes supporting reliable transmission system transformation needed to enable things like plant retirements, integrating or replacement generation resources, and meeting Duke Energy's carbon reduction objectives.

Q. Thank you. And turning to you, Ms. Farver, would you please state your full name and business address for the record.

A. (Maura Farver) My name is Maura Farver. And my business address is 411 Fayetteville Street in Raleigh, North Carolina.

Q. And by whom are you employed and in what capacity?

A. I am employed by Duke Energy as the

distributed energy technology strategy and policy director in North Carolina.

Q. And can you please briefly describe your role and responsibilities at Duke Energy.

A. Yes. I am responsible for coordinating business strategy work streams, and regulatory and policy efforts related to renewable energy, both as standalone generation resources and wind combined with battery storage for DEC and DEP in North Carolina.

Q. And Mr. Roberts, did the panel cause to be prefiled in this docket direct testimony consisting of 65 pages with five exhibits and a summary of your testimony?

A. (Sammy Roberts) Yes.

Q. Do you have any changes to your direct testimony, summary, or exhibits at this time?

A. Yes, I do. I have a couple of changes. On page 21, beginning on line 1, the sentence that begins with "This slide from the presentation," should be replaced with the following sentence: "This slide from the presentation shows that an additional 4.5 gigawatts to 5.4 gigawatts of additional solar would need to be interconnected to the DEC and DEP systems and operational by January 1, 2030, in order to meet

70 percent CO2 reduction by 2034 with offshore wind or small modular reactor resources included, or 70 percent CO2 reduction by 2030 with offshore wind resources respectively."

CHAIR MITCHELL: That was with offshore wind resources respectively?

THE WITNESS: That's correct. Okay. And the second correction is on page 36, line 8. The number 5,000 should be replaced with "approximately 4,900" so that the sentence begins "of the approximately 4,900 megawatts of proposals received."

Q. Thank you. Other than those changes, if I were to ask you the same questions today that appear in your prefiled direct testimony, would your answers remain the same?

A. Yes.

Q. And Exhibit 5 to the panel's direct testimony is confidential, correct?

A. That's correct.

MS. KELLS: At this time, Chair Mitchell, I move that the Transmission Panel's direct testimony be entered into the record as corrected today as if given orally from the stand.

CHAIR MITCHELL: All right. Hearing no objection, motion's allowed.

(Whereupon, the prefiled direct testimony of Transmission Panel of Sammy Roberts and Maura Farver was copied into the record as if given orally from the stand.)

(Whereupon, per request for admittance in Volume 19, the prefiled summary of the Transmission Panel of Sammy Roberts and Maura Farver was also 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: Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, 2022 Biennial Integrated Resource Plan And Carbon Plan	)))))))	**DIRECT TESTIMONY OF DEWEY S. ROBERTS II AND MAURA FARVER ON BEHALF OF DUKE ENERGY CAROLINAS, LLC AND DUKE ENERGY PROGRESS, LLC**

TABLE OF CONTENTS

I. INTRODUCTION AND SUMMARY

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

A. My name is Dewey S. Roberts II (Sammy) and my business address is 3401 Hillsborough Street, Raleigh, North Carolina.

Q. BEFORE INTRODUCING YOURSELF FURTHER, WOULD YOU PLEASE INTRODUCE THE PANEL.

A. Yes. I am appearing on behalf of Duke Energy Carolinas, LLC ("DEC") and Duke Energy Progress, LLC ("DEP" and together with DEC, the "Companies" or "Duke Energy") together with Maura Farver on the "Transmission Panel." Ms. Farver will introduce herself.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy as General Manager, Transmission Planning and Operations Strategy.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AS GENERAL MANAGER, TRANSMISSION PLANNING AND OPERATIONS STRATEGY.

A. I have primary responsibility for the development of mid-term and long-term strategy for Transmission Planning and Operations. This responsibility includes mid-term and long-term planning to support reliable transmission system transformation needed to enable coal plant retirements and to integrate replacement generation resources and meet Duke Energy's carbon reduction objectives. This responsibility also includes developing strategies and standards for transformed system operations necessary to reliably operate the Duke Energy power systems to facilitate a smooth transition through planned coal plant retirements and integrating increasing amounts of renewable energy resources and storage.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from North Carolina State University in 1987 with a Bachelor of Science Degree in Electrical Engineering. I also obtained a Master of Science Degree in Electrical Engineering from North Carolina State University in 1990 and a Master of Business Administration Degree from North Carolina State University in 2004. I am also a registered Professional Engineer in the state of North Carolina, and I was a Certified System Operator by the North American Electric Reliability Corporation through 2021.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined Carolina Power & Light Company, a predecessor of DEP, in 1990 and have held several engineering and management positions in Nuclear Engineering, Engineering and Technical Services, System Operator Training, Portfolio Management, Transmission Services, and System Operations. These positions include: Project Engineer, Manager – Transmission Services, Manager – Power System Operations, Director – System Operations, and General Manager – System Operations. In July 2020, I assumed my current position.

Q. MR. ROBERTS, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") OR ANY OTHER UTILITY COMMISSION?

A. Yes. I have testified before this Commission and the Public Service Commission of South Carolinas ("PSCSC") on several occasions in the Progress Energy Carolinas (now DEP) annual fuel proceedings. Also, I testified before the PSCSC in the Companies' 2020 South Carolina IRP proceedings.

Q. MS. FARVER, PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Maura Farver, and my business address is 411 Fayetteville Street, Raleigh, North Carolina.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?

A. I am employed by Duke Energy as the Distributed Energy Technology Strategy and Policy Director in North Carolina.

Q. PLEASE DESCRIBE YOUR CURRENT RESPONSIBILITIES AS DISTRIBUTED ENERGY TECHNOLOGY STRATEGY AND POLICY DIRECTOR.

A. I am responsible for coordinating business strategy work streams and regulatory and policy efforts related to renewable energy as a stand-alone generation resource and when combined with battery storage for DEC and DEP in North Carolina. Distributed energy technologies involve many areas of the Companies' operations, including resource planning, project development, interconnection, procurement, contract management, stakeholder engagement, fuel and systems optimization, operations, and customer programs. My role is to help maintain alignment between these teams and develop strategy as to how best to procure renewable energy resources to help meet Duke Energy's carbon reduction objectives.

Q. PLEASE BRIEFLY SUMMARIZE YOUR EDUCATION AND PROFESSIONAL QUALIFICATIONS.

A. I graduated from Duke University in 2005 with a Bachelor of Science degree in Environmental Science. I also obtained a joint Master of Environmental Management degree from Duke University's Nicholas School of the Environment and Master of Business Administration from UNC Kenan-Flagler Business School in 2013.

Q. PLEASE SUMMARIZE YOUR WORK EXPERIENCE.

A. I joined Duke Energy as the Distributed Energy Technology Strategy and Policy Director in 2019. Previously, I worked at Southern California Edison as the Manager of Short-Term Planning (managing a team that developed the day-ahead bidding strategy for the California Independent System Operator energy market), as a Senior Project Manager on a bottoms-up resource planning pilot (the Preferred Resources Pilot), and as a Project Manager for energy storage strategy.

Q. MS. FARVER, HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NORTH CAROLINA UTILITIES COMMISSION OR ANY OTHER UTILITY COMMISSION?

A. No.

Q. MR. ROBERTS AND MS. FARVER, ARE YOU INCLUDING ANY EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. Transmission Panel Exhibit 1 provides DEC mapping of historical studies to Red-Zone Transmission Expansion Plan ("RZEP") projects. Transmission Panel Exhibit 2 provides DEP mapping of historical studies to RZEP projects. Transmission Panel Exhibits 3 and 4 provide DEC and DEP supplemental planning studies developed to assess the need for constructing the RZEP projects to interconnect new solar generation necessary to meet the Carolinas Carbon Plan ("Carbon Plan") targets, as discussed below. Confidential Transmission Panel Exhibit 5 provides a map of potential points of interconnection for offshore wind energy facilities off the North Carolina coast.

Q. MR. ROBERTS, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Executing the energy transition away from coal generation, including the Carbon Plan, will require a momentous transformation of and investment in the DEC and DEP transmission systems to interconnect and safely and reliably deliver the unprecedented amounts of new supply-side resources that will be needed to retire significant amounts of coal-fired generation and achieve the carbon emission reduction targets established by North Carolina Session Law 2021-165 ("HB 951"). The purpose of my testimony is to provide an overview of this significant transmission system transformation and investment associated with executing the Companies' proposed near-term plan for coal retirements and interconnecting incremental resources as well as enabling execution of the intermediate-term to long-term plans associated with the Carbon Plan portfolios as further support for the grid-related information, plans, and cost and other assumptions presented in the Carbon Plan.

As part of providing this overview, my direct testimony addresses several key themes contained in Appendix P (Transmission System Planning and Grid Transformation) of the Carbon Plan. First, I describe the Companies' transmission planning processes for ensuring a reliable system compliant with NERC Reliability Standards and Federal Energy Regulatory Commission ("FERC") orders, including processes for evaluating the interconnection facilities and network upgrades necessary for integrating incremental resources. Second, I describe the importance of integrating transmission planning with resource planning and the need for proactive transmission planning to achieve timely generator retirements and interconnections needed to mitigate energy transition and Carbon Plan execution risk. This section of the testimony will include a description of the RZEP projects and the critical need for these projects to enable the interconnection of large amounts of solar needed to execute the energy transition and Carbon Plan successfully. Third, I address transmission planning for coal retirements and generator replacement. Fourth, I describe transmission planning efforts for enabling offshore wind, including analysis conducted to determine a preferred point of interconnection for reliably injecting offshore wind energy into the DEP transmission system. Fifth, I describe transmission planning analysis as well as risk considerations for off-system purchases of capacity. My testimony will conclude with a description of the path forward for transmission planning needed to ensure reliability, affordability, and effective execution of the Carbon Plan. I also respond to intervenor comments concerning these topics.

Q. MS. FARVER, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. The 2022 Solar Procurement for the DEC and DEP systems in the Carolinas is now underway, and the Companies have received a robust market response including a significant number of projects located in the "red zones" discussed by Witness Sammy Roberts. My testimony provides an update on the 2022 Solar Procurement and additional information on the need for the RZEP projects to interconnect new generation and successfully achieve the objectives of the 2022 Solar Procurement and future solar procurements.

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

A. HB 951 provides that the Carbon Plan to be developed by the Commission should "consider . . . transmission" along with supply-side and demand-side resources as a core component of planning for the least-cost pathway to transition the Companies' systems and achieve the State's carbon dioxide ("CO_2") emission reduction targets. Appendix P to the Carbon Plan extensively describes the Companies' local and regional transmission planning processes as well as the key transmission planning considerations that informed the Carbon Plan. Our testimony builds on this analysis and supports the following points:

1. HB 951 establishes new public policy goals requiring new generation and other resources that will necessarily inform the Companies' transmission system planning processes as outlined in the joint Open Access Transmission Tariff ("OATT"). The Companies are requesting the Commission to direct Duke Energy to continue to study future transmission needs to reliably implement the Carbon Plan primarily through the North Carolina Transmission Planning Collaborative ("NCTPC").
2. The Companies support transitioning to a more proactive transmission planning process and are committed to working through the FERC approved NCTPC local transmission planning process to collaboratively assess and plan for the transmission projects that will be needed to interconnect new generation identified as needed in the Plan and to achieve HB 951's emission reduction targets.
3. The RZEP projects are necessary to execute the energy transition and Carbon Plan and meet the carbon emission reduction targets established in HB 951 in a least-cost manner. Additional planning analysis presented in our testimony provides further support for the RZEP projects and the Companies request Commission acknowledgement of this need for the RZEP projects.
4. Retiring existing coal facilities that support the grid and integrating incremental resources forecasted in the Carbon Plan resource portfolios will require significant investment in the DEC and DEP transmission

systems. The Companies are pursuing FERC approval of the generator replacement process to enable more efficient and cost-effective interconnection of generating facilities at existing sites.

5. The Carbon Plan reasonably integrates transmission costs associated with energy transition into the resource planning analysis through providing transmission cost adders representing dollar per watt ("$/W") transmission network upgrade costs for specific resource types.
6. Based on the 2020 NCTPC Offshore Wind Study and additional Duke Energy cost analysis, considering cost effectiveness, reliability, and interconnectivity, the New Bern point of interconnection is the most appropriate for importing up to 1600 MW of offshore wind into the DEP system.
7. There are a number of system risks associated with relying on significant incremental off-system capacity purchases as a Carbon Plan resource.

II. DEC AND DEP TRANSMISSION PLANNING AND GENERATOR INTERCONNECTION PROCESSES

Q. PLEASE REINTRODUCE THE COMPANIES' TRANSMISSION PLANNING PROCESSES.

A. As detailed in Carbon Plan Appendix P, the Companies' local and regional transmission system planning processes are designed to ensure open, coordinated, and transparent planning of the transmission system under FERC requirements and to establish a process for ensuring the continued adequacy and reliability of the transmission system, to provide for generator interconnections, and to meet the NERC TPL-001 requirements.[1] The robust transmission planning processes that Duke Energy engages in today have developed over time based upon a series of significant FERC orders including Order No. 890 (2007) and Order No. 1000 (2011) that form the regulatory framework for local, regional, and inter-regional transmission planning.

Attachment N-1 of the Companies' OATT sets forth the local, regional, and interregional planning processes by which the Companies meet these requirements, satisfy the transmission planning principles of FERC Order Nos. 890 and 1000, and produce local and regional transmission plans. To meet these requirements DEC and DEP are members of the NCTPC local transmission planning process and the Southeastern Regional Transmission Planning ("SERTP") process. The development of local and regional transmission plans ensures reliability is maintained or improved with the addition of new planned generation and transmission projects while reliably serving DEC and DEP customers.

As reflected in Attachment N-1, Part I of the OATT,[2] the NCTPC Local Planning Process addresses transmission upgrades needed to maintain reliability and to integrate new generation resources and/or loads in the Companies' North Carolina and South Carolina service areas. The local planning process includes a base reliability study ("base case") that evaluates

[1] See Carbon Plan Appendix P at 4-10.
[2] Joint Open Access Tariff of Duke Energy Carolinas, LLC, Duke Energy Florida, LLC, and Duke Energy Progress, LLC ("Joint OATT"), *available at* http://www.ferc.duke-energy.com/Tariffs /Joint_OATT.pdf.

each Transmission System's ability to meet projected load with a defined set of resources as well as the needs of firm point-to-point transmission service customers, whose needs are reflected in their transmission contracts and reservations. A resource supply analysis is also conducted to evaluate transmission system impacts for other potential resource supply options to meet future load requirements.

The NCTPC annually develops a single, coordinated local transmission plan ("Local Transmission Plan") that appropriately balances costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources to meet the needs of Load Serving Entities as well as Transmission Customers under the OATT. This local transmission planning process also enables solutions to public policy requirements to be considered for adoption into the Local Transmission Plan.[3] Appendix P provides additional detail on the organization of the NCTPC and the SERTP process, as well as other regional transmission planning working groups.[4]

Q. PLEASE DESCRIBE IN FURTHER DETAIL DEC'S AND DEP'S PARTICIPATION IN LOCAL TRANSMISSION PLANNING PROCESSES.

A. DEC and DEP participate in the NCTPC local transmission planning process as members of the Oversight/Steering Committee ("OSC") and Planning Working Group ("PWG"), whose duties are described in more detail in Appendix P. Two

[3] Joint OATT, Attachment N-1, Section 5.7.1.
[4] Carbon Plan Appendix P at 8-10.

other load-serving entities—Electricities of North Carolina ("Electricities") and North Carolina Electric Membership Corporation ("NCEMC")—are also members of the OSC and PWG, with representatives of Electricities currently chairing the OSC. Working with their fellow OSC and PWG members, DEC and DEP annually develop a Local Transmission Plan for the Duke Energy Carolinas transmission systems across North Carolina and South Carolina. Consistent with the terms of Attachment N-1, the OSC and PWG engage with the Transmission Advisory Group ("TAG"), composed of interested stakeholders, to solicit input and recommendations to incorporate into the Local Transmission Plan. TAG participants have the opportunity to propose alternative transmission, generation, and/or demand response solutions to address reliability, economic, and/or public policy transmission needs.

Q. PLEASE REINTRODUCE THE COMPANIES' GENERATOR INTERCONNECTION PROCESSES USED FOR STUDYING FERC AND STATE GENERATOR INTERCONNECTION REQUESTS.

A. Transmission planning is integrally linked to planning for and reliably interconnecting new generating facilities. Generator interconnection requests are studied in accordance with the FERC Large and Small Generator Interconnection Procedures ("LGIP" and "SGIP") contained in the OATT and the North Carolina and South Carolina state generator interconnection procedures applicable to qualifying facilities selling their output to DEC or DEP under the Public Utility Regulatory Policies Act of 1978 ("PURPA"). Through queue reform, the Companies have now successfully transitioned to administering a first-ready, first-served Cluster Study process called the Definitive Interconnection System Impact Study ("DISIS") to study the transmission and distribution system impacts of all FERC and state jurisdictional interconnection customers.

Q. PLEASE UPDATE THE COMMISSION ON THE VOLUMES OF NEW REQUESTS FOR INTERCONNECTION IN THE 2022 DISIS.

A. The initial DISIS Cluster Enrollment Window has now closed and the Customer Engagement Window is underway and continues through August 28, 2022. At the close of the Enrollment Window, there were 5.37 GW of all resource types representing 30 projects in DEC and 5.376 GW of all resource types representing 63 projects in DEP. In aggregate, 10.746 GW of projects in DEC and DEP requested interconnection in the 2022 DISIS. In DEC, over 1.1 GW of solar facilities (17 projects) ranging from 20 MW to 176 MW requested interconnection. In DEP, over 5.16 GW of solar facilities representing 58 projects ranging from 48 MW to 275 MW requested interconnection in DEP. These numbers represent submissions in the enrollment window, which closed June 29, 2022. As we are now in the Customer Engagement Window, some projects have withdrawn from the 2022 DISIS, and other panels' testimony may refer to the remaining projects as of a later date. Additional detail on the volume and locations of 2022 DISIS Interconnection Requests that have bid into 2022 Solar Procurement are addressed later in this testimony.

Q. MR. ROBERTS, WHY IS IT IMPORTANT TO UNDERSTAND THE COMPANIES' TRANSMISSION PLANNING AND GENERATOR INTERCONNECTION PROCESSES IN THE CONTEXT OF THE CARBON PLAN?

A. An effective transmission planning process is necessary for system adequacy and reliability as the Companies navigate the pathway toward retiring coal generation and meeting Carbon Plan objectives, and Duke Energy views the transmission planning process as a key enabler of achieving the goals of the Carbon Plan. As discussed further in the next section of this testimony, transmission planning must be integrated with resource planning in order to meet those targets, consistent with the Commission's and FERC's respective authorities.

III. INTEGRATING TRANSMISSION PLANNING WITH RESOURCE PLANNING AND THE NEED FOR PROACTIVE TRANSMISSION PLANNING

Q. PLEASE ADDRESS HOW THE CARBON PLAN BUILDS ON THE 2020 IRP PROCEEDING TO SPECIFICALLY FOCUS ON TRANSMISSION PLANNING AND GRID TRANSFORMATION.

A. Transmission planning, specifically including the cost and timing of enabling coal retirements and interconnecting new less carbon-intensive resources, was a key area of focus in the North Carolina 2020 IRP proceeding, including at the October 6, 2021, Technical Conference. The Commission's November 19, 2021 Final Order on the Companies' 2020 IRPs[5] highlighted the Commission's increasing focus on transmission planning and the transmission network upgrades required to retire existing coal facilities and to integrate portfolios of new supply-side resources needed to achieve a least-cost energy transition as mandated by HB 951. The Commission specifically directed the Companies to analyze the anticipated or likely grid impacts associated with alternative resource portfolios modeled in the IRPs and to continue to refine transmission network upgrade cost estimates for incremental resources to take into account the most recent system impact study results. The Commission also directed the Companies to assess the critical transmission network upgrades required to enable interconnection of incremental resources identified, build on recent transmission planning studies completed by the NCTPC, and continue to analyze the costs, risks, and reliability aspects of potential off-system purchases, specifically including refining the cost and timing for importing increased capacity from PJM.

In response to these Commission directives and recognizing transmission planning's critical role in enabling the energy transition planned within the Carbon Plan, Duke Energy provided significant detail on transmission planning and grid transformation considerations in Appendix P and incorporated updated transmission costs based upon best available information in the Carbon Plan modeling.

[5] *Order Accepting Integrated Resource Plans, REPS, and CPRE Program Plans with Conditions and Providing Further Direction for Future Planning*, Docket No. E-100, Sub 165 at 15-16 (November 19, 2021).

Q. WHY IS INTEGRATING TRANSMISSION PLANNING WITH RESOURCE PLANNING IMPORTANT FOR EXECUTION OF THE CAROLINAS ENERGY TRANSITION WITHIN THE CARBON PLAN?

A. The momentous shift in the generating fleet expected over the course of the next decade and beyond will require an equally momentous build-out of the transmission system to support reliable operations, ensure generator deliverability for a changing resource portfolio, and economically serve changing customer demand.

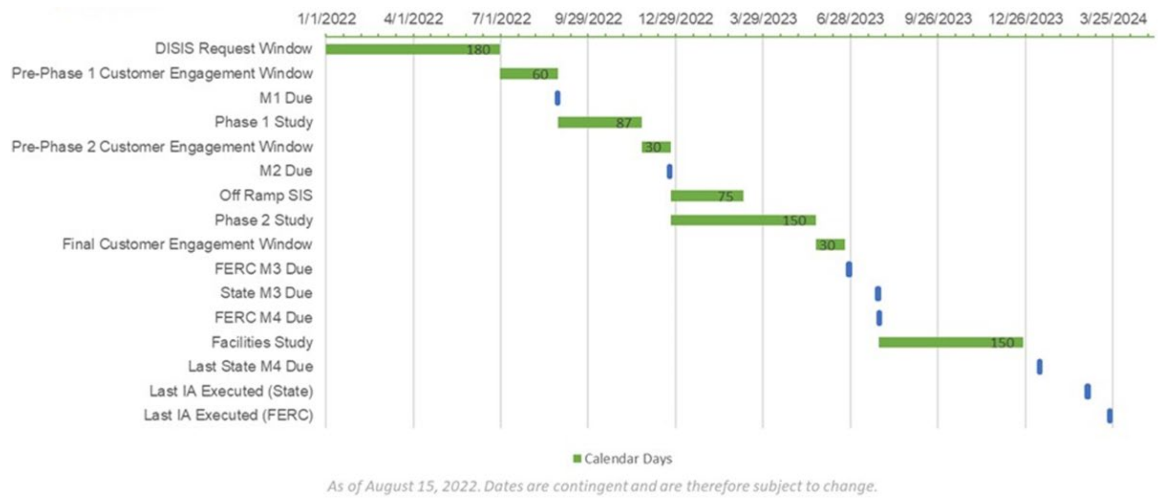
In the Carolinas, the Commission and the PSCSC are largely responsible for guiding resource planning for new generation to serve the Companies' dual-state systems and ensuring integrated resource plans provide for reliable electric service in a least-cost manner. The Commission has now also been tasked with developing a Carbon Plan that will comply with carbon reduction objectives in a least-cost manner and is the framework for the energy transition away from coal generation that has been happening on the DEC and DEP system for a number of years now. FERC is responsible for regulating transmission planning and ensuring bulk electric system reliability, just and reasonable rates for transmission customers, and rules around requirements and planning for large and small generator interconnection. These regulated approaches must be closely coordinated and sufficiently forward-looking to ensure alignment in order to successfully meet the overall objective of maintaining or improving reliability and reducing carbon emissions in an affordable manner.

If the transmission planning and resource planning processes are misaligned leading to insufficient transmission development on a timely basis, the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation puts Carbon Plan and energy transition execution at risk. Proactive transmission planning informed by reasonable assumptions and expectations of retirements and future generation is therefore necessary to mitigate this risk and ensure that transmission development and construction do not create an impediment to achieving carbon emission reductions and system transformation.

Q. HOW WILL THIS INTEGRATION OF RESOURCE PLANNING AND TRANSMISSION PLANNING MITIGATE EXECUTION RISK?

A. As discussed above and shown by Figure 1 below, the current timeline for a generator requesting interconnection to the DEC or DEP system and reaching commercial operations can be several years.

Figure 1: 2022 DISIS Timeline



The current interconnection process requires an approximately two and one quarter year period from the time the interconnection request is made to the time an interconnection agreement is signed. Only after the interconnection agreement is signed will a transmission project be initiated for any necessary transmission network upgrades identified in the Phase 1 study of the DISIS cycle. Actions (or inaction) of the interconnection customer after interconnection agreement execution can further delay interconnection timelines. With some transmission network upgrades requiring 3 to 5 years to plan, design, and construct, the time from requesting interconnection to commercial operations can, in certain cases, potentially take over seven years. Following this reactive generator-interconnection driven approach to transmission upgrades would create significant timeline challenges and potentially an insurmountable hurdle with respect to Carbon Plan execution within the requirements of HB 951. Specifically, if the Companies pursue interconnection of high-volume resources such as solar in a piecemeal, reactive manner, transmission network upgrade projects will be delayed until interconnection agreements materialize from the DISIS process. These delays will in turn significantly challenge the Companies' ability to meet the requirements of the Carbon Plan and achieve an orderly energy transition for the Carolinas.

Therefore, Duke Energy believes that a proactive transmission planning approach is necessary to meet the requirements of the Carbon Plan in the specified timeframes. To meet these objectives, DEC and DEP must work within the NCTPC framework to evolve from a reactive mode that primarily relies on the generator interconnection process to integrate new generation to a more proactive, forward-looking view that anticipates the transmission projects that will be needed to meet future generation needs. Integrating resource planning and transmission planning and proactively planning and constructing transmission projects needed to integrate the new resources selected by the Commission in the Carbon Plan will be a necessary step to mitigate execution risk and to overcome the challenges associated with scaling up clean energy resources in the Companies' systems in a timely manner.

The Public Staff recognizes the challenges of executing the Carbon Plan and finds that "Duke should move from a purely reactive transmission upgrade approach, where it constructs transmission only after a generator has requested interconnection, to a planning process that also considers proactive upgrades in anticipation of future generation required by the Carbon Plan adopted by the

Commission."[6] As the Public Staff recognizes, setting an executable least-cost path to meeting the Carbon Plan objectives requires a decision of whether to build proactive upgrades in anticipation of future interconnections or reactive upgrades in response to interconnection requests.

Q. HOW ARE DEC AND DEP PLANNING TO USE A PROACTIVE TRANSMISSION EXPANSION PLANNING APPROACH FOR IMPLEMENTING THE CARBON PLAN?

A. As discussed in Appendix P, the energy transition reflected in the Carbon Plan will require significant investment in the transmission system on an aggressive timeline to interconnect the significant amounts of incremental new solar, solar plus storage, stand-alone storage, wind, small modular reactors and new natural gas generation resources identified as needed in the Carbon Plan and to reliably retire the coal units that currently support the grid. The Companies will not be able in all cases to wait on solar procurements, associated DISIS timelines, and associated resource interconnection agreements to drive the start of transmission network upgrade projects that could take 3 to 5 years to construct and still meet the timeline for aggressive CO_2 reduction requirements outlined in HB 951.

Through January 1, 2030, a significant amount of additional solar is needed to pursue any one of the four Carbon Plan portfolios as shown on page

[6] Public Staff Comments at 114.

43 of the June 27, 2022 NCTPC TAG meeting presentation.[7] This slide from the presentation shows that an additional 4.5 GW to 5.4 GW of additional solar will need to be interconnected to the DEC and DEP systems and operational by January 1, 2030, in order to meet 70% CO_2 reduction by 2034 with offshore wind and small modular reactor ("SMR") resources included or 70% CO_2 reduction by 2030 without offshore wind or SMR resources, respectively. To meet this need, DEC and DEP have been engaged in the Local Transmission Planning process through the NCTPC in 2022 with respect to introducing the RZEP projects for inclusion in a Local Transmission Plan that includes the necessary transmission upgrades to accommodate timely integration of a significant amount of additional solar in high solar viability areas of the DEC and DEP systems. The RZEP projects will unlock these high solar viability areas where numerous generator interconnection studies have shown that solar resources desire to interconnect.

The history of solar generator interconnection requests in DEC and DEP shows that solar facilities continue to request interconnection in these red zones, despite published guidance from DEC and DEP that locating solar in the red zones will require significant network upgrades. Developers have continued to submit interconnection requests in the red zones, and to then withdraw from the interconnection queue when the cost allocation for transmission network upgrades necessary to enable interconnection of their resource is realized. This

7 North Carolina Transmission Planning Collaborative, TAG Meeting Webinar (June 27, 2022), http://www.nctpc.org/nctpc/document/TAG/2022-06-27/M_Mat/TAG_Meeting_Presentation_for_06-27_2022_FINAL.pdf (last visited Aug. 19, 2022).

piecemeal approach to transmission planning and generator interconnection presents a significant challenge to Carbon Plan and energy transition execution; more broadly, this challenge is a recognized concern in the industry as evidenced by the issuance of the recent FERC NOPR.[8]

Q. PLEASE UPDATE THE COMMISSION ON RECENT DEVELOPMENTS IN THE NCTPC LOCAL TRANSMISSION PLANNING PROCESS TO CONSIDER THE RED-ZONE EXPANSION PLAN PROJECTS.

A. The Carbon Plan reflects the need for proactive consideration of the RZEP projects to enable successful interconnection of significant incremental resources, primarily solar resources, as identified in the Carbon Plan portfolios. Duke Energy explained that the Companies plan to follow the required Attachment N-1 planning process for NCTPC TAG stakeholder input and coordination and to seek OSC approval with the goal of incorporating the RZEP projects into the update of the 2021 Local Transmission Plan by mid-year 2022.[9]

Prior to the Carbon Plan filing, in March 2022, the Companies introduced to the NCTPC OSC the RZEP projects as generator interconnection study informed solutions to common transmission constraints that had been increasingly defined by DEC and DEP transmission planners since May 2018 and that were repeated impediments to solar interconnections in the red-zone

[8] *Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection*, Notice of Proposed Rulemaking, 179 FERC ¶ 61,028 (2022).
[9] Carbon Plan Appendix P at 13.

areas. In April 2022, the Companies shared with the OSC initial mapping of generator interconnection studies to RZEP projects identified as necessary upgrades in the studies. After the Carbon Plan filing, in June 2022, the Companies provided updated information on the number of times interconnection studies identified the RZEP projects as necessary upgrades to enable interconnection. Also in June 2022, the NCTPC distributed a draft of the 2021 Mid-year Update Report to the TAG for review prior to the June TAG meeting. In addition to other updates to the Local Transmission Plan approved at the end of 2021, the draft 2021 Mid-Year Update Report proposed adding the RZEP projects to the Local Transmission Plan.

On June 27, 2022, the Companies presented the 2021 Plan Mid-Year Update Report to the TAG. The Mid-Year Update Report included several slides reflecting the reasons the RZEP projects are needed to enable solar interconnections to integrate significant amounts of generation and for executing the Carbon Plan. At that time, the plan was to seek approval of the 2021 Plan Mid-Year Update Report from the OSC by mid-August pending feedback and additional input received from TAG stakeholders. Based on current estimated construction schedules, which would be re-evaluated upon OSC approval, certain RZEP projects have lead times of up to four and a half years. Aside from preliminary engineering work on the RZEP projects, which has been conducted primarily as a result of legal obligations from interconnection requests where RZEP projects were previously identified, no significant development work has been completed for the RZEP projects. In order to provide sufficient time to construct the RZEP projects necessary to integrate over 4,500 MW of incremental solar generation between 2026 and 2030, as identified in the Companies' IRP, DEC and DEP believed at the time and continue to believe that expeditious action by the NCTPC and approval by the OSC is necessary for Carbon Plan execution.

However, based on feedback and additional input received from TAG stakeholders and the Commission's directive in the 2022 Solar Procurement dockets for the Companies to exclude the RZEP projects from being considered in the baseline for the 2022 DISIS Phase 1 Study, the NCTPC communicated that the RZEP projects would be removed from consideration to be included in the 2021 Plan Mid-Year Update Report.

Q. DO THE COMPANIES CONTINUE TO SUPPORT PROACTIVE DEVELOPMENT OF THE RZEP PROJECTS THROUGH THE NCTPC?

A. Yes. The Companies and many TAG participants continue to recognize the need for these projects to interconnect new solar generating facilities and to support the energy transition and achieving Carbon Plan objectives. The Companies also recognize that the accelerated pace for presenting the RZEP projects to the TAG presented limited opportunities for engagement and understanding of the need for the RZEP, although the transmission needs addressed by the RZEP have been known for several years. Through subsequent engagement with Public Staff after the June TAG meeting and the Commission directive in the 2022 Solar Procurement dockets, DEC and DEP agreed to perform supplemental planning studies based on agreed-upon planning assumptions to further evaluate the need for the RZEP. These supplemental planning studies, which will be described in greater detail later in this testimony, reinforce the need for the majority of the RZEP projects, and the Companies' current plan is to reintroduce the RZEP projects into the NCTPC process, supported by multiple transmission planning studies and the supplemental planning studies, as necessary to integrate anticipated future generation and execute the Carbon Plan. These RZEP projects will be reintroduced through recommended inclusion in the 2022 Local Transmission Plan that will be reviewed by the TAG and considered for approval by the OSC later this year. The Companies anticipate additional TAG meetings from now until the end of the year to review the need, benefits, and estimated costs of the RZEP projects.

Q. THE PUBLIC STAFF HIGHLIGHTS PROACTIVE TRANSMISSION PLANNING AS NEEDED TO DEVELOP A LEAST-COST CARBON PLAN THAT INCORPORATES "LEAST REGRETS" TRANSMISSION PROJECTS. HOW DOES DUKE ENERGY VIEW THE RZEP PROJECTS WITH REGARD TO EXECUTING THE CARBON PLAN?

A. The Companies view the RZEP projects as a prudent and necessary first step to interconnect to the DEC and DEP systems the volume of solar needed to execute the Carbon Plan for the aforementioned reasons, *e.g.*, unlocking access to high solar viability regions of the DEC and DEP systems. As stated above, up to 5.4 GW of additional solar will need to be interconnected to the DEC and

DEP systems by 2030 for Carbon Plan execution. Based on numerous transmission planning studies, the high solar viability region located in the red zones will need to have the associated transmission constraints relieved to enable interconnecting this volume of solar within the timeframes necessary to meet carbon reduction objectives.

Furthermore, there will be secondary benefits from these RZEP projects. The increase in transmission capability will help to enable solar located in the red zones to charge stand-alone battery storage that is located closer to load centers. During high solar capacity factor, blue-sky days when solar energy is creating excess energy on the system, rather than curtail solar output this excess energy can be used to charge stand-alone battery storage located closer to load centers. This carbon-free energy can be discharged to meet load center demand during the winter and summer net demand peak periods. Another secondary benefit resulting from the RZEP projects is that they will replace aging, less resilient equipment with new, more resilient equipment such as replacing wood poles with steel poles.

Q. **THE COMMISSION'S JUNE 10 ORDER IN THE 2022 SOLAR PROCUREMENT PROCEEDING[10] DIRECTED THAT THE COMPANIES AND OTHER PARTIES SUPPORTING PROACTIVE APPROVAL OF THE RZEP PROJECTS AS NECESSARY TO EXECUTE THE CARBON PLAN SHOULD PROVIDE SUBSTANTIAL EVIDENCE TO SUPPORT THE NEED FOR THE RZEP PROJECTS. ARE THE COMPANIES PROVIDING THAT EVIDENCE HERE?**

A. Yes. Transmission Panel Exhibits 1 and 2 show the information provided by the Companies in response to Public Staff Data Request No. 24, Item 2 reflecting additional mapping of past generator interconnection studies with the RZEP projects. This mapping reflects the number of past generator interconnection and interdependency grouping studies completed between 2017 and 2021 identifying each RZEP transmission network upgrade project as necessary for interconnecting solar facilities being studied. While several of the studies identifying the need for the RZEP projects were conducted under the old serial queue study process, several of these same projects were also identified in the recent Transitional Cluster Study results. Furthermore, as noted above and discussed further below, the Companies have conducted supplemental cluster-like studies of recent solar generator interconnection requests to provide additional evidence of the need for the RZEP projects.

---

[10] *Order Approving Request for Proposals and Pro Forma Power Purchase Agreement Subject to Amendments*, Docket Nos. E-2, Sub 1297, E-7, Sub 1268 (June 10, 2022).

Q. PLEASE DESCRIBE THE PURPOSE OF THE SUPPLEMENTAL STUDIES CONDUCTED BY THE COMPANIES.

A. The purpose of these studies was to further analyze the need for proactive transmission upgrades to help Duke Energy meet Carbon Plan and Integrated Resource Plan goals in the Carolinas. Prior studies in the serial generator interconnection process and the Transitional Cluster Study have demonstrated the need for transmission upgrades that mitigate common constraints but cannot be financed by solar generation developers. In these studies, prior solar generation interconnection requests that withdrew from the queue were studied with the latest Duke Energy transmission power flow models, using cluster study methods, to determine overloaded transmission facilities, appropriate upgrades, and contributions to the overloads by the studied solar generators.

Q. PLEASE DESCRIBE THE SCOPE OF AND CRITERIA USED FOR THE SUPPLEMENTAL STUDIES.

A. DEC and DEP conducted supplemental cluster-type studies of the most recent generator interconnection requests for 5.4 GW, which aligns with the level of solar identified by the Carbon Plan Portfolio 1 as needed to meet a 70% CO_2 reduction objective by 2030. To conduct a forward-looking study of this type, assumptions about the MW size and location of future generation are necessary. Using the most recent generator interconnection requests as the basis for generator MW size and location assumptions is a non-discriminatory and objective approach to the selection of the 5.4 GW used in the supplemental studies. From the most recent generator interconnection requests, DEC studied

41 solar projects representing 1,937 MW, and DEP studied 45 solar projects representing 3,527 MW. In DEC, only one request was considered per 44 kV line due to the significant local impact of more than one request on a 44 kV line. DEC and DEP did not study solar projects greater than 175 MW due to the localized impact that these projects have on network upgrades needed for interconnection. The supplemental study scope and criteria were discussed and agreed upon with the Public Staff in advance of performing the study.

Q. PLEASE DESCRIBE THE RESULTS OF THE SUPPLEMENTAL STUDIES.

A. Transmission Panel Exhibits 3 and 4 provide the results of the DEC and DEP supplemental planning studies. For DEC, the study results support all four (4) RZEP projects identified in DEC. For solar projects requesting interconnection to 44 kV circuits, even though DEC is limiting to one solar project for a given 44 kV circuit, overloads are still reflected in the results. This result may be mitigated by limiting the aggregate size of solar (transmission, distribution) on the 44 kV circuit. The DEC study results reflect that the four (4) RZEP projects are needed to enable 981 MW of solar projects to be interconnected in the red zones.

For DEP, the study results support eleven (11) RZEP projects identified in DEP. The study results reflect that three (3) of the DEP RZEP projects could be delayed until future studies again show a reliability need or generation addition need for the project. Even though the Erwin-Milburnie 230 kV, the Rockingham-West End 230 kV West, and the Sutton-Wallace 230 kV lines were not identified as network upgrades necessary for interconnecting the solar projects studied, past transmission planning studies have shown these upgrades to be needed for interconnecting solar projects. Based on the scope of the study, DEC and DEP did not need to utilize the historical generator interconnection requests that had previously been mapped to the Erwin-Milburnie 230 and Sutton-Wallace 230 upgrade to get the 5.4 GW needed to meet the study requirements. Economic development load may require the upgrade of the Rockingham-West End 230 kV West line. The three network upgrades not identified by the study are all pole replacement upgrades, with the exception of the Erwin-Milburnie 230 kV line that additionally requires replacement of blades on four-line switches, with all projects requiring only a single outage/maintenance season to implement the upgrades, although coordination with other transmission work will dictate the schedule needed. Once these network upgrades are identified as necessary for interconnecting solar projects in future studies, these projects should not present a Carbon Plan execution risk due to the single season required to implement the upgrade.

The DEP study results reflect eleven (11) RZEP projects are needed to enable 2,778 MW of solar projects to be interconnected in the red zones.

As reflected in the supplemental study results, additional network upgrades were identified as necessary to interconnect 5.4 GW or more of solar inside and outside the red zones. However, the majority of these additional network upgrades identified are not projected to be as extensive, or should receive as high a priority, as compared with the identified RZEP projects and thus should not present a Carbon Plan execution risk.

Q. IN SUMMARY, DOES THE COMPANIES' FURTHER ANALYSIS OF THE RZEP PROJECTS DEMONSTRATE THAT NCTPC APPROVAL OF THESE TRANSMISSION PROJECTS AS PART OF THE NCTPC'S 2022 LOCAL TRANSMISSION PLAN IS NECESSARY TO EXECUTE THE CARBON PLAN AND TO ACHIEVE THE PUBLIC POLICY OBJECTIVES IN HB 951?

A. Yes. The Companies' further analysis reveals that the majority of the same identified RZEP upgrade projects that were previously identified are needed to reliably interconnect 5.4 GW of solar to the DEC and DEP systems. Furthermore, Project Management analysis of the timelines for engineering, procurement of materials, and construction of these projects reflects an aggressive schedule is needed in order to complete most of the RZEP projects within a four-year period. As I discussed above with respect to the interplay between transmission planning and resource planning, the lack of timely transmission project development and construction can become an obstacle for resource planning, and if the RZEP projects are not approved as part of the NCTPC's Local Transmission Plan, Carbon Plan execution is at risk.

Q. IN ADDITION TO THE NEED FOR THE RZEP PROJECTS TO FACILITATE TIMELY ACHIEVEMENT OF ENERGY TRANSITION AND CARBON PLAN GOALS, DO THE RZEP PROJECTS PROVIDE ADDITIONAL BENEFITS?

A. Yes. Transmission utilizes two primary value models to quantify Reliability benefits based off investment types. Capacity & Customer Planning investment types utilize a value model that calculates reliability benefits based off observed overload/voltage criteria for the investment and measures the societal impact of an outage to customers utilizing Interruption Cost Estimate or "ICE" Calculator[11] data based off the probability of failure. Conversely, Asset replacement investment types utilize a value model that calculates reliability benefits based off asset deterioration curves for the investment and measures the societal impact of an outage utilizing ICE data based off the probability of failure.

As shown in DEP's Technical Conference CBA materials presented on July 15, 2022, in Docket No. E-2, Sub 1300, the RZEP projects were initially evaluated utilizing our planning value model to quantify reliability benefits of the investment. Since the RZEP rebuild projects involve replacing aging conductors and structures with new, more reliable equipment and new higher capacity conductors generally have lower impedance that reduces transmission losses, Duke Energy also evaluated the RZEP projects utilizing the asset

[11] The ICE Calculator is a tool designed for electric reliability planners at utilities, government organizations or other entities that are interested in estimating interruption costs and/or the benefits associated with reliability improvements.

replacement value model to quantify reliability benefits of replacing aging infrastructure. While the value models for these projects is different than the methodology used previously, we conclude this evaluation provides a better representation of the benefits being achieved for these investments due to the large aging asset base that is being replaced.

The results for the CBA using the asset replacement value model show the four DEC RZEP projects identified in the DEC supplemental study with scores ranging from 5.1 to 22.5 with an average score of 14.6, and the eleven DEP RZEP projects identified in the DEP supplemental study with scores ranging from 10.5 to 21.4 with an average score of 15.5.

Q. DO THESE SCORES ASCRIBE VALUE TO COMPLIANCE WITH HB 951 CARBON REDUCTION TARGETS OR ANY OTHER CARBON REDUCTION VALUE?

A. No.

Q. USING THE ASSET REPLACEMENT VALUE MODEL, WHAT IS THE COMBINED COST-BENEFIT RATIO FOR THE 11 RZEP PROJECTS?

A. The combined cost-benefit ratio for the 15 RZEP projects identified by the DEC and DEP supplemental studies is 15.1.

Q. HAVE THE COMPANIES OBSERVED ANY NON-RELIABILITY BENEFITS THAT CAN BE ASCRIBED TO THE RZEP PROJECTS?

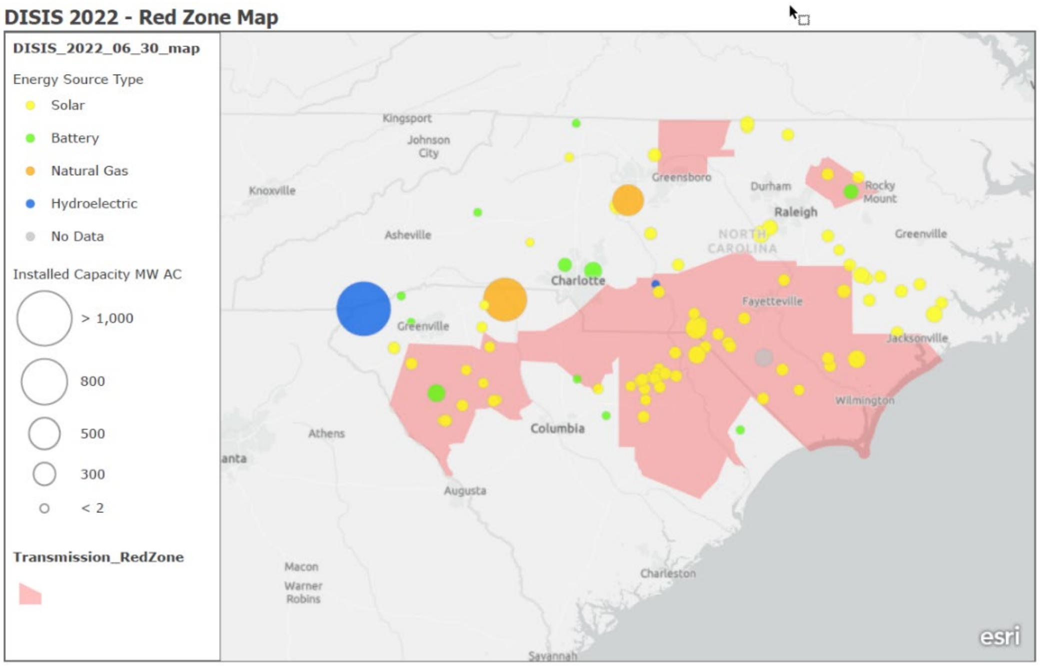
A. Yes. The Companies' capital cost forecast tool, developed by a third party, indicates that the largest PV sites have up to a $0.22 per Watt benefit when compared to the standard transmission-connected PV sites that are less than 80

MW. In the 2022 DISIS Cluster there are three large sites that sum to 675 MW and are requesting interconnection in the red zones. If the RZEP enables these sites to be constructed, in lieu of smaller sites outside of the red zones, another approximately $140 million of benefits could be realized.

Q. DOES THE VOLUME AND LOCATION OF SOLAR PROJECTS IN THE 2022 DISIS SUPPORT DUKE ENERGY'S VIEW THAT THE RZEP PROJECTS ARE NEEDED TO INTERCONNECT NEW GENERATING RESOURCES?

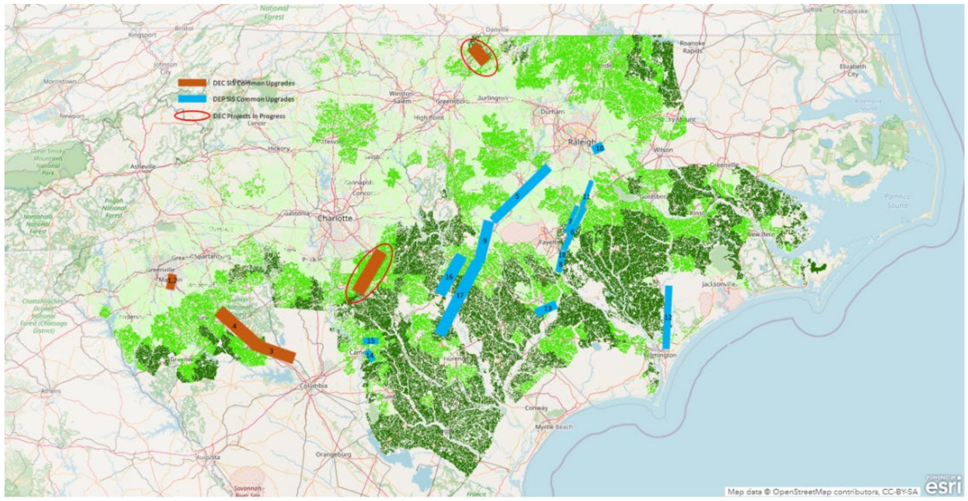
A. Yes. As demonstrated by Figure 2, a significant volume of 2022 DISIS solar facilities are requesting interconnection in the red zones.

Figure 2: 2022 DISIS Red-Zone Map



Furthermore, Figure 3 demonstrates the location of the RZEP projects relative to areas of high solar viability, primarily in the red zones. This image shows the darker green, high solar viability areas, where a significant volume of 2022 DISIS solar facilities are requesting interconnection and the original identified RZEP projects that provide the upgraded transmission capability to move the carbon-free solar energy from these facilities to meet customer demand and to supply carbon-free energy for storage for peaking capacity and other system needs.

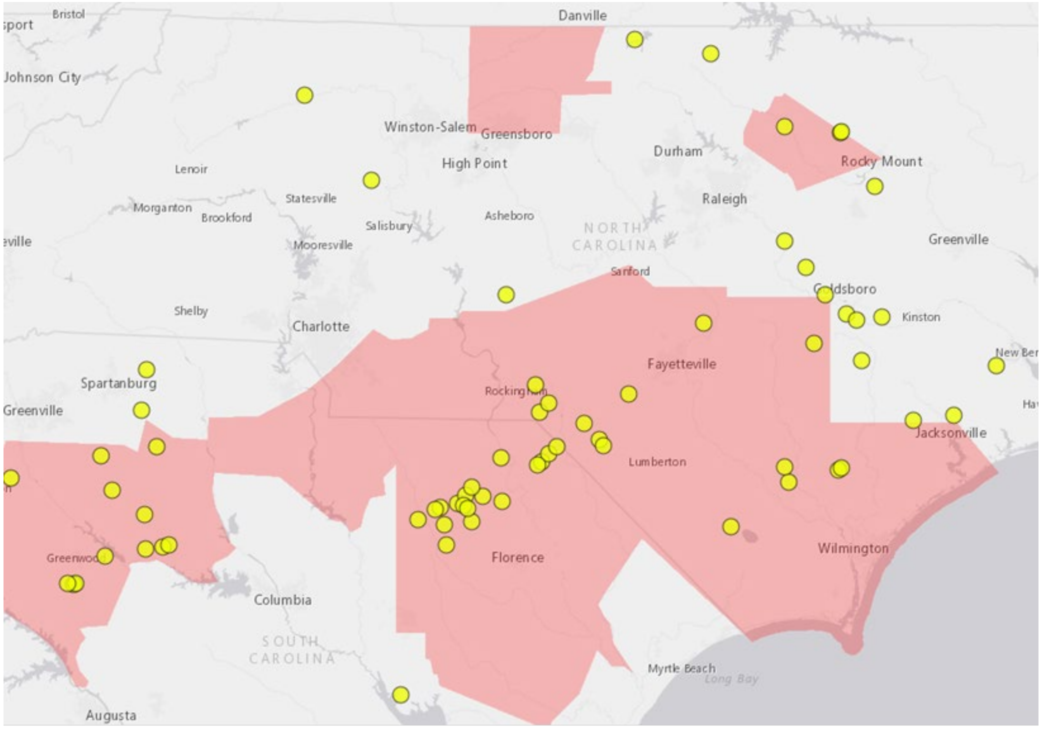
Figure 3: Solar Viability Map with RZEP Projects



Q. MS. FARVER, DOES THE MARKET RESPONSE IN THE 2022 SOLAR PROCUREMENT FURTHER DEMONSTRATE THE CONTINUED MARKET INTEREST IN DEVELOPING PROJECTS IN THE RED ZONES?

A. Yes. The bid window for 2022 Solar Procurement recently closed on July 22, 2022. Of the more than 5,000 MW of proposals received, over 70% of the MW are located in known red-zone areas. These known congested areas have been shared with market participants ahead of the 2022 Solar Procurement, and all three CPRE RFPs, and yet this information does not seem to drive project development to non-congested areas in any significant way. Figure 4 below shows the locations of the proposals in the 2022 Solar Procurement overlaid with the known "red zones."

Figure 4: Overlay of 2022 Solar Procurement Proposals with Red Zones



Q. THE PUBLIC STAFF IDENTIFIES "TWO MAIN RISK FACTORS" ASSOCIATED WITH FUTURE PROACTIVE TRANSMISSION PLANNING TO SUCCESSFULLY EXECUTE THE CARBON PLAN. HOW DO THE RZEP PROJECTS ADDRESS THESE RISKS?

A. The Public Staff explains in its comments that it "identified two main risk factors with future transmission construction: (1) insufficient time to build large-scale transmission upgrades to allow economically selected generation; and (2) wasted proactive transmission assets. Duke Energy's currently planned transmission upgrades and timelines show an increasing risk of not meeting goals set forth in Section 110.9 by 2030. The second risk factor, wasted proactive transmission assets, can be further divided into two categories: (1) building transmission that is either not utilized or under-utilized; and (2) building transmission only to have it replaced by future upgrades in the first 10 to 15 years of the original asset's 40- to 60-year asset life. To the extent that proactive upgrade planning can address these two risk factors, proactive upgrades should begin as soon as practicable."[12]

With respect to the first risk the Public Staff identifies, the Companies agree that proactive transmission planning and associated construction of identified necessary projects is critical to meeting energy transition and Carbon Plan objectives in a timely manner. The Companies also do not view future underutilization of the RZEP projects as a material concern because of the historic demonstration of a significant amount of solar that would site and rely on the upgrades. For other proactive transmission development in the future, this risk is mitigated by developing reasonable assumptions about future scenarios where there is general consensus those assumptions will materialize.

With respect to the second risk, the Companies' transmission planners do consider and apply engineering judgement when a network upgrade is identified as necessary to provide assurance that the current transmission network upgrade will not need additional upgrades in the foreseeable future. As an example, the proposed RZEP upgrade of 26.6 miles of the Cape Fear – West End 230 kV line plans to use steel structures with bundled 1590 MCM conductor per phase replacing the existing wood H-frame structures with single 1272 MCM conductor per phase. This upgrade will increase the rating from the existing 591 MVA to 1195 MVA, a 121% increase in rating. Duke Energy will

[12] Public Staff Comments at 112-113.

continue to engage with Public Staff and other stakeholders through the iterative NCTPC local transmission planning process to ensure that these risks are appropriately considered and prudently managed.

Q. PLEASE SUMMARIZE WHY THE COMMISSION SHOULD ACKNOWLEDGE THAT THE RZEP PROJECTS ARE NEEDED TO EXECUTE THE CARBON PLAN.

A. The Commission should acknowledge that the RZEP projects are needed to execute energy transition and the Carbon Plan for two primary reasons: 1) this testimony demonstrates the need for and benefits from implementing the RZEP projects; and 2) the Companies' near-term procurement and development activities and longer-term consideration of both the 2030 and beyond 2030 pathways supported by the Carbon Plan portfolios, for which the Companies are seeking Commission approval, will all require a significant volume of solar to be interconnected to meet carbon reduction objectives, thus justifying the need for the RZEP projects. The Commission's acknowledgement of the need for the RZEP projects to interconnect new solar generation and to meet the objectives of the Carbon Plan will provide strong evidence to the NCTPC that approval of the RZEP projects in the 2022 Local Transmission Plan is a reasonable and prudent step. In the alternative, based on the results of the Supplemental Studies, the Commission should acknowledge the need for the 15 RZEP projects identified in those studies.

Q. THE PUBLIC STAFF AND OTHER PARTIES SUGGEST THAT THE NCTPC PLANNING PROCESS ALSO NEEDS TO EVOLVE TO MEET THE EVOLVING NEEDS OF EXECUTING THE CARBON PLAN. DO THE COMPANIES AGREE?

A. Yes. The Companies will work with other NCTPC OSC members and stakeholders to consider changes to the local transmission planning processes to improve coordination with Carbon Plan execution and ensure timely and robust review of transmission projects necessary to meet anticipated generation needs. The Companies also see that the NCTPC local planning processes can evolve and improve by incorporating deliverability studies that more closely align with the scope of current generator interconnection studies. Additionally, after the increased interest in TAG participation seen with the RZEP projects, the Companies also foresee the need for clarifications to the process and procedures for obtaining TAG feedback.

In alignment with a proposal in the FERC Transmission Planning NOPR, the Public Staff recommends that the Companies extend long-term transmission planning to 20 years. The Companies will consider this recommendation; however, moving to a 20-year transmission planning horizon introduces challenges that would need to be addressed. Numerous study inputs such as projecting resource types, sizes, and locations, climate and its impact on resource output, availability, customer demand, and model topology would all experience more changes and decreased certainty over a 20-year period. Moving to a 20-year transmission plan would need to be combined with scenario-based planning change cases for any decision-making to be meaningful on a 20-year time horizon. Although focused on long-term, scenario planning for regional transmission planning processes, FERC's on-going Transmission Planning NOPR proceeding may provide useful insights on how to incorporate more scenario-planning into NCTPC local transmission processes. Additionally, for this change to be successful, not only would DEC and DEP need to adopt a 20-year transmission planning horizon process, but the local, regional, and interregional transmission planning processes would also need to adopt a 20-year transmission planning process. Finally, any such changes to transmission planning processes will require FERC-approved tariff changes.

Q. CPSA RECOMMENDS THE COMMISSION INITIATE A PROCEEDING INCLUDING BUT NOT LIMITED TO CONVENING A TECHNICAL CONFERENCE WITH THE GOAL OF ESTABLISHING A PROACTIVE, LONG-TERM TRANSMISSION PLANNING PROCESS CONSISTENT WITH APPLICABLE FERC REQUIREMENTS.[13] HOW DO YOU RESPOND?

A. As stated above, the Companies agree that the local transmission planning process can be evolved and improved and are supportive of the NCTPC initiating a review to evaluate changes to the local transmission process and to consider changes to Attachment N-1 of the Joint OATT that could be filed with FERC. In support of that review, the Companies anticipate that a stakeholder

[13] CPSA Comments at 69.

process, like the Companies have used successfully in the past for reforms to their Joint OATT, would be helpful to gather feedback on improvements to the local transmission planning process. As I noted earlier, there may also be useful insight to gain from FERC's ongoing Transmission Planning NOPR proceeding about how to incorporate long-term, scenario-based analysis into transmission planning processes. Waiting for FERC to act in the Transmission Planning NOPR would not only offer additional insight on scenario-based planning reforms, but also help any potential local planning changes to better align with regional planning changes that FERC may require.

Q. CPSA ALSO RECOMMENDS THAT THE COMMISSION HIRE A THIRD PARTY, ASSISTED BY AN INDEPENDENT TECHNICAL ADVISORY COMMITTEE, TO STUDY THE ACHIEVABILITY OF HIGHER SOLAR INTERCONNECTION RATES IN DUKE ENERGY'S TERRITORY, AND ADVISE THE COMMISSION ON MEASURES THAT CAN BE TAKEN TO EXPEDITE INTERCONNECTION.[14] HOW DO YOU RESPOND?

A. While CPSA's recommendation appears to be premised on the assumption that Duke Energy has failed to interconnect a significant amount of solar generation facilities and to pursue efficiency improvements to the interconnection process, the opposite is in fact the case. The Companies are among national leaders in terms of the amount of solar generation that they have interconnected to their systems with 4,470 MW of utility-scale solar connected and another 1,669 MW

[14] CPSA Comments at 69.

under construction as of August 1, 2022. Furthermore, the Companies have proactively implemented queue reform to improve the efficiency of solar interconnections.

In addition to what they have already accomplished, the Companies continue to work to identify additional opportunities to improve efficiencies, which will help to achieve higher solar interconnection rates needed to meet energy transition needs and Carbon Plan objectives. After approval of and effective transition to the cluster study process, the Companies initiated process improvement workshops during the first quarter of 2022, to identify and pursue actions to advance the pace and volume of facility interconnection. The actions identified are already underway, are expected to reduce interconnection duration. These interconnection improvements focus on engagement and program alignment. Engagement improvements address additional coordination with developers that includes more clearly defined requirements and expectations for both Duke Energy and interconnection customers. Alignment of program functions will result in improvements to standard engineering designs, reduced construction duration, formalized measurement of interconnection performance, and executive oversight. For improvements to be realized, it will take commitment from both developers and Duke Energy to adhere to the refined process and timelines. The Companies understand that the interconnection of sufficient volumes of solar is critical to execute the Carbon Plan and depends on interconnection process improvement as well as the RZEP projects.

Q. PLEASE RESPOND TO THE SUGGESTION THAT DUKE ENERGY SHOULD BE REQUIRED TO CONSIDER GRID ENHANCING TECHNOLOGIES AS PART OF THE TRANSMISSION PLANNING PROCESS.

A. No such requirement is needed because the Companies have and will continue to investigate the potential benefits from integrating existing and emerging technological solutions to accomplish the mission of providing reliable and affordable service to customers while pursuing an accelerated carbon reduction mission to execute a Carbon Plan. Duke Energy is aware of the application of Grid Enhancing Technologies ("GETs") and other similar technologies to increase the capacity, efficiency, and/or reliability of our transmission system. Over time we have applied some technologies and evaluated others. Duke Energy has installed Remedial Action Schemes and load swap-overs, series and switchable reactors and phase shifters; and has begun to enable, when necessary, active curtailment of some solar generation for control of power flows on the grid. Application of controllable variable line reactors and dynamic line rating monitors have been evaluated. Duke Energy will continue to assess opportunities for use of battery storage as a non-wires solution as described in Appendix S (Integrated Systems and Operations Planning) and is monitoring the industry's use of adaptive topology control. Ambient adjusted line ratings in the operating horizon will be implemented in the near future in accordance with FERC Order No. 881. Duke Energy continues to evaluate these technologies, and notes that application of some GETs could increase the probability of placing the system in unanalyzed conditions in real time and complicate operators' ability to maintain situational awareness. Therefore, Duke Energy intends to be prudent in GETs application.

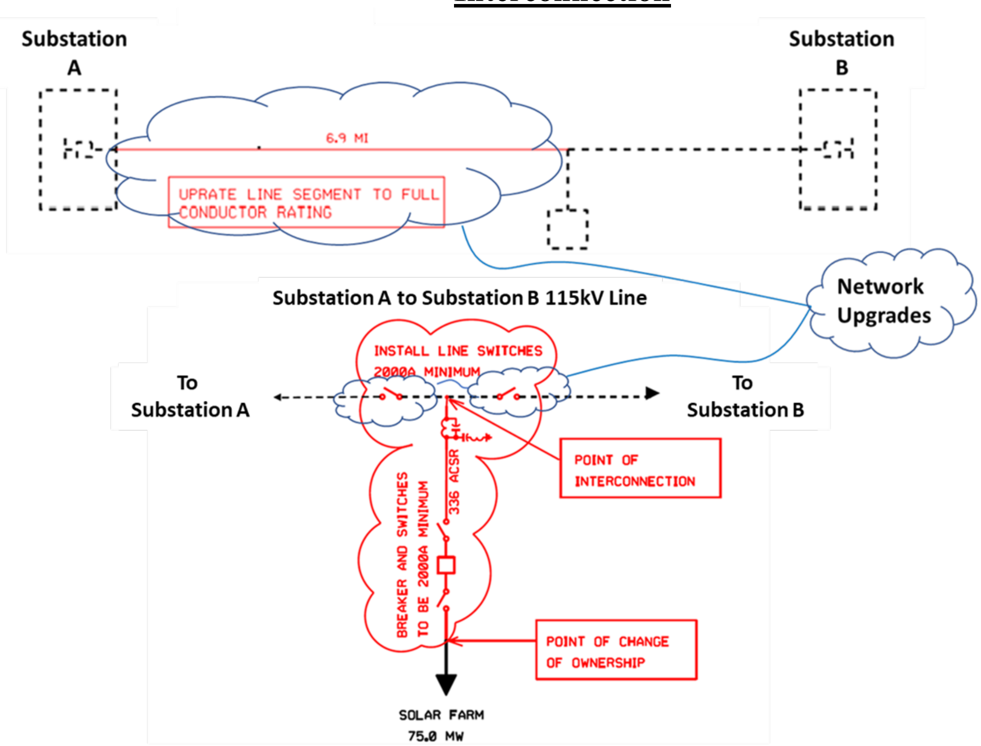
With respect to investigating and applying new conductor technologies, Duke Energy does consider the use of high temperature, low sag conductors for reconductoring projects. Currently, Aluminum Conductor Steel Supported or Aluminum Conductor Steel Supported Trapezoidal are the most commonly used HTLS conductors at Duke Energy. Duke Energy has experience with low sag composite core conductors, but does not currently consider either composite core or composite reinforced conductor due to recent installation concerns. Thus, Duke Energy is always investigating and, where it makes engineering and economic sense, applying technological solutions to the benefit of an efficient, reliable power system.

IV. TRANSMISSION COSTS IN CARBON PLAN MODELING

Q. PLEASE EXPLAIN THE TYPE OF TRANSMISSION NETWORK UPGRADE COSTS ESTIMATED AND INCLUDED IN THE SELECTION OF RESOURCES FOR THE CARBON PLAN PORTFOLIOS.

A. Figure 5 below provides a representation of the types of Network Upgrades for which Generic Transmission Network Upgrade Costs were estimated as an input for selecting resources for the Carbon Plan portfolios. This example reflects the network upgrades required for interconnecting a 75 MW solar facility, as reflected in Appendix E – Quantitative Analysis, Table E-44. The extent of the upgrades and associated costs can vary significantly based on the size and location of the resource as well as the existing transmission system near the point of interconnection for the resource. Costs for Distribution Upgrades or Interconnection Facilities were not included in the Generic Transmission Network Upgrade Costs. The costs for Interconnection Facilities are the responsibility of the generation customer seeking interconnection and thus are considered to be part of the generation asset costs for transmission-connected resource selection in the Carbon Plan portfolios.

<u>Figure 5: Typical Network Upgrades for 75 MW Solar Generator Interconnection</u>



Q. HOW DOES THE CARBON PLAN INTEGRATE TRANSMISSION SYSTEM COSTS INTO PLANNING ANALYSIS?

A. As described in Appendix E, the Carbon Plan reasonably integrates transmission costs into the resource planning analysis through providing transmission cost adders representing dollar per watt ("$/W") transmission network upgrade costs for specific resource types. These $/W transmission network upgrade cost proxies, as reflected in Appendix E, Table E-44, were primarily derived from the most recent historical generator interconnection studies where available. Where larger resources' output is injected into a single point of interconnection (*e.g.*, offshore wind), the network upgrade cost proxies are lumpy due to the upgrades necessary to accommodate a given output level. Thus, the first 800 MW of offshore wind injected reliably into the DEP system is estimated to have a network upgrade cost proxy of $0.45/W [$2022], whereas 2,400 MW of offshore wind injected reliably into the DEP system is estimated to have a network upgrade cost proxy of $0.22/W [$2022] due to the further utilization of the same network upgrades needed to inject up to 1,600 MW of offshore wind reliably into the DEP system. More detail concerning transmission planning for enabling offshore wind and associated transmission cost estimates is provided in Section VI of this testimony.

Q. DOES THE PUBLIC STAFF AGREE WITH THE TRANSMISSION NETWORK UPGRADE COST ADDERS USED IN MODELING RESOURCE COSTS TO DEVELOP THE CARBON PLAN PORTFOLIOS?

A. Yes. The Public Staff states in its comments that it "does not take issue with Duke's proposed transmission cost adders and the modeling methodology utilized in its Proposed Carbon Plan."[15] As recommended by the Public Staff, in future Carbon Plans, the Companies will continue to refine transmission cost estimates, update the transmission cost adders based on the most recent interconnection cluster study in combination with engineering judgment, and provide support showing how the transmission cost adders were derived.[16]

Q. DO ANY INTERVENORS RECOMMEND ALTERNATIVE TRANSMISSION COST ADDERS?

A. Yes. CPSA's modeling consultant, the Brattle Group, elected to use different transmission cost assumptions in its modeling.[17] CPSA explains that Brattle relied upon the Southeast Wind Coalition's 2022 Offshore Wind Study and assumed inflation-adjusted upgrade costs of $.441/W for offshore wind in 2030—in Real 2022 dollars, arguing this assumed interconnection cost is substantially lower than Duke Energy's assumption for the first 800 MW tranche and around half of the cost assumed by Duke Energy for the second 800 MW tranche. For all other resources, Brattle assumed transmission costs of

---

[15] Public Staff Comments at 103.
[16] Public Staff Comments at 104.
[17] CPSA Comments at 29.

$.10/W. Battery storage paired with solar was assumed to have no additional network upgrade costs beyond those assigned to the solar facility, which was also the Companies' assumption.

Based on Duke Energy's analysis, Brattle's transmission cost adders are low. The transmission cost adders as shown in Table E-44 of Appendix E for interconnecting offshore wind into the DEP New Bern substation with the potential to scale to over 1,600 MW if needed were based on transmission planning estimates that are discussed further in Section VI below. For injecting 800 MW of offshore wind into New Bern substation, it was estimated that $360 million of 230 kV upgrades would need to be constructed and for 1,600 MW to be injected into the New Bern substation, a new 500 kV line and 230 kV upgrades would need to be constructed for an estimated cost of $995 million. As noted above, most of the other transmission cost adders utilized historical generator interconnection results as the cost basis. As of the date of the Carbon Plan filing, no formal generator interconnection study has been performed for the offshore wind resource.

V. <u>TRANSMISSION PLANNING FOR COAL RETIREMENTS</u>

Q. BRIEFLY DESCRIBE THE ROLE OF TRANSMISSION PLANNING AS THE COMPANIES EVALUATE COAL RETIREMENT AS ADDRESSED IN THE CARBON PLAN.

A. With respect to the coal retirement plans reflected in the Carbon Plan, Duke Energy will need to ensure that any transmission projects required to accommodate those retirements are in place prior to planned retirement dates. The Carbon Plan coal retirement dates are reflected in Table 1.[18]

<u>Table 1: Carbon Plan Portfolio Coal Retirements</u>

Table 3-1: Coal Unit Retirements (effective by January 1 of year shown)

Unit	Utility	Winter Capacity [MW]	Effective Year (Jan 1)
Allen 1[2]	DEC	167	2024
Allen 5[2]	DEC	259	2024
Belews Creek 1	DEC	1,110	2036
Belews Creek 2	DEC	1,110	2036
Cliffside 5	DEC	546	2026
Marshall 1	DEC	380	2029
Marshall 2	DEC	380	2029
Marshall 3	DEC	658	2033
Marshall 4	DEC	660	2033
Mayo 1	DEP	713	2029
Roxboro 1	DEP	380	2029
Roxboro 2	DEP	673	2029
Roxboro 3	DEP	698	2028-2034[3]
Roxboro 4	DEP	711	2028-2034[3]

[1]Cliffside 6 is assumed to cease coal operations by the beginning of 2036 and was not included in the Carbon Plan's Coal Retirement Analysis because the unit is capable of operating 100% on natural gas
[2]Allen 1 and 5 retirements are planned by 2024 and were not re-optimized in the Carbon Plan's Coal Retirement Analysis
[3]Retirement year for Roxboro Units 3 and 4 vary by portfolio, with retirement of those units effective 2028 in P1, 2032 in P2, and 2034 in P3 and P4

Q. PLEASE DESCRIBE THE TRANSMISSON PLANNING ASSOCIATED WITH THE COAL RETIREMENT TIMELINES GIVEN IN THE CARBON PLAN PORTFOLIOS.

A. As described in Appendix P, based on the planned retirement dates of coal-fired generators on the DEC and DEP systems, varying levels of transmission planning analysis and considerations have occurred based on different scenarios for generation replacement.[19] Several of these scenarios reveal the dependence of replacing the retiring generation on-site connected to the same electrical point of interconnection. This is a major consideration with respect to the timing

[18] This is the same table that was presented as Table 3-1 at p. 7 of Chapter 3 to the Carbon Plan.
[19] Carbon Plan Appendix P at 15-16.

for which the generation retirement can occur if long-term transmission upgrades can be avoided, and was a major driver in the Companies' decision to seek FERC approval to incorporate a Generation Replacement process into the LGIP as identified in the Carbon Plan.

Q. PLEASE PROVIDE AN UPDATE ON THE GENERATION REPLACEMENT PROCESS.

A. FERC approval of an expedited generator replacement process will be critical to efficient, timely, and cost-effective replacement of retired coal-fired generation with new generation that interconnects at the same switchyard where the retiring generation is located. Utilization of the same switchyard for interconnection will save the cost of potentially expensive interconnection facilities and potentially network upgrades that would be required if the same replacement generation was constructed at a greenfield site. The Companies petitioned FERC for approval of a generator replacement process on June 1, 2022, in Docket No. ER22-2007-000, and are awaiting a final order. If approved, the process will create efficiencies, reduce timelines, and minimize costs associated with replacing generating facilities and relying upon existing transmission capability facilities at retiring sites, which will help the Companies accomplish a momentous shift in their generation fleet, particularly in time to achieve 70% carbon reduction within the time frame required by HB 951.

Q. WHAT IS DUKE ENERGY'S PLAN FOR REPLACING THE RETIRED COAL GENERATION?

A. The Companies' plans for replacing the retiring coal generation are described in Chapter 3 of the Carbon Plan, Table 3-1 (shown above as Table 1) with pages 6-7 providing the coal retirement dates supported by Carbon Plan modeling and Chapter 4, Table 4-2 pages 9-10 describing the Execution Plans for coal retirements. With respect to these plans, the Companies not only need to consider the resource adequacy associated with the replacement resources, but also need to plan for grid impacts such as voltage support, changing power flows, and the need for associated transmission upgrades and/or greenfield transmission infrastructure, should replacement generation not be located at the coal retirement site.

Q. HAVE YOU CONSIDERED THE TRANSMISSION IMPACTS AND RISKS OF THE ACCELERATED COAL RETIREMENT SCHEDULES RECOMMENDED BY OTHER PARTIES?

A. Yes. I have reviewed the proposed portfolios offered by Synapse for NCSEA et al. and Gabel/Strategen on behalf of Tech Customers.[20] First, Synapse argues that Duke Energy justifies proposed coal retirement delays beyond the economically optimal coal retirement dates by noting the need to consider transmission constraints and replacement resources when retiring these units, but alleges that Duke Energy's proposed Carbon Plan does not provide enough

[20] NCSEA et al. Synapse Report at Sections 2, 3 (suggesting earlier retirements of Belews Creek Units 1-2, Cliffside Unit 5, and Marshall Units 1-2); Tech Customers Gabel Report at 5-6, 27-28 (recommending accelerating coal unit retirements to 2027 and retiring all coal units by 2030).

information to understand the nature of the problem or the potential ways to address these issues.[21]

Synapse fails to recognize real-world execution and operations risks and relies too heavily on accepting the modeling results as a foolproof, reliable portfolio with no need for scrutinizing the results for execution risks or operational reliability risks. As discussed in Carbon Plan Appendix P, there are several retirement scenarios in which potentially-significant transmission upgrades would need to occur if the replacement generation is not located at the site of the retiring coal generation: "If any Marshall coal units are retired and not replaced with new generation on-site, then significant transmission projects will be needed (i.e., upgrade McGuire to Marshall 230 kV lines) and in service by December 2028"... to meet the Marshall Units 1, 2 retirement dates.[22] This schedule would be extremely aggressive since this transmission upgrade project has not been initiated. Appendix P also explains that "Belews Creek units will continue to operate into the 2030s and DEC plans to evaluate transmission upgrades to enable retirements as the planned retirement date approaches. However, preliminary analysis does suggest that transmission upgrades will be required to retire the 2,220 MW of capacity at Belews Creek if not replaced with new generation on-site and coincident with the retirements."[23] If replacement generation is not onsite at Belews Creek, the transmission upgrades that would be needed for addressing the Northern Region Voltage

[21] NCSEA et al. Synapse Report at 28-29.
[22] Carbon Plan Appendix P at 15.
[23] Carbon Plan Appendix P at 15-16.

Collapse NERC Interconnection Reliability Operating Limit could be extensive and would likely not be able to be completed to facilitate a 2030 retirement as recommended by Tech Customers or by Synapse in its Regional Resources portfolio.

With respect to retiring Roxboro and Mayo coal generation by 2030, "Currently, there is no available import capability from DEC to DEP. Thus, if the Roxboro/Mayo replacement generation is located in DEC and requires import into DEP, then additional, more costly and time-consuming upgrades would be required. Conceptual transmission projects that would likely be needed would be a Durham-Parkwood Tie 500 kV interconnection, a Bynum 500/230 kV Switching Station interconnection along with associated line upgrades, and potentially a Roxboro Plant-Sadler Tie 230 kV interconnection."[24] Most of these upgrades are greenfield transmission projects and would not be able to be completed to enable a 2030 retirement date for Roxboro and Mayo replacement generation. Synapse does not meaningfully engage with these challenges and merely states that "[t]o the extent that local transmission or generation resources are needed to retire these units, Duke Energy could identify and accelerate development of these resources, including using transparent, all-source procurement for replacement generation resources, to meet economical retirement dates."[25] Gabel assumes for purposes of its report that all retiring coal generation is replaced on-site, and so also does not

[24] Carbon Plan Appendix P at 16.
[25] Synapse Report at 28.

meaningfully engage with this issue.[26] Therefore, I have significant executability concerns with Synapse's and Gabel's proposed portfolios and underlying resource planning assumptions from a transmission planning perspective.

VI. TRANSMISSION PLANNING FOR ENABLING OFFSHORE WIND

Q. PLEASE DESCRIBE THE TRANSMISSION PLANNING ANALYSIS ASSOCIATED WITH INJECTING OFFSHORE WIND INTO THE DUKE ENERGY TRANSMISSION SYSTEM.

A. The 2020 NCTPC Offshore Wind Study[27] provided a comprehensive screening analysis for several potential points of interconnection and injection of varying levels of offshore wind into the DEP transmission system. It should be noted, however, that the 2020 NCTPC Offshore Wind Study was not an official generator interconnection study responding to an interconnection request being submitted to the DEP Transmission Provider in accordance with the FERC approved process in the OATT. For an official specification of the requirements for interconnection facilities and identified transmission network upgrades for reliably injecting a given level of offshore wind energy into the DEP system, official generator interconnection studies must be conducted.

However, the 2020 NCTPC Offshore Wind Study results are very informative with respect to identifying a reliable, cost-effective point of

---

[26] Gabel Report at 5.
[27] North Carolina Transmission Planning Collaborative, Report on the NCTPC 2020 Offshore Wind Study (June 7, 2021), *available at* 2020_NCTPC_Offshore_Wind_Report_06_07_2021-FINAL Rev 2.pdf.

interconnection for injecting offshore wind energy into the DEP transmission system.

Q. WHY HAVE THE COMPANIES IDENTIFIED NEW BERN AS THE PREFERRED POINT OF INTERCONNECTION FOR INJECTING OFFSHORE WIND INTO THE DUKE ENERGY TRANSMISSION SYSTEM?

A. The 2020 NCTPC Offshore Wind Study screened 32 potential injection sites and, based on the injection capability and cost results of that screening analysis, further analyzed the feasibility and costs of injecting up to 5,000 MW of offshore wind power at up to the three most promising sites based on those criteria in eastern DEP. The power from the offshore wind plants was delivered 40% to DEP and 60% to DEC. Rather than studying pre-determined MW levels, it was requested that NCTPC find the MW breakpoints at which transmission upgrades would be needed. As reflected in the 2020 NCTPC Offshore Wind Study Report, New Bern 230 kV Substation would be one of the three most promising sites to inject up to 3.2 GW of offshore wind based on cost and feasibility. No other site stood out for both high MW capability and relatively lower cost.

New Bern is the most feasible and economic point of interconnection ("POI") for injecting 800 MW to 1600 MW of offshore wind, with capability to inject even more offshore wind energy. In addition to the 2020 NCTPC Offshore Wind Study, Duke Energy performed a cost analysis to determine the most cost-effective transmission path including the POI for importing up to

1600 MW of offshore wind into the DEP system. This cost analysis, which included both offshore and onshore transmission costs (network transmission and interconnection facilities), revealed that the New Bern POI was approximately $700 million less compared with other potential POIs. The New Bern POI also allows the Companies to utilize existing right-of-way for the network transmission and will reduce risk and cost for an offshore wind project.

Q. DID THE COMPANIES CONSIDER ANY OTHER POINTS OF INTERCONNECTION FOR INJECTING OFFSHORE WIND INTO THE DUKE ENERGY TRANSMISSION SYSTEM AND, IF SO, WHY ARE THOSE POINTS OF INTERCONNECTION NOT PREFERRED?

A. Yes. The Companies considered additional points of interconnection, but the overall cost-effectiveness of the New Bern POI outperformed these alternatives. Two additional sites were selected to provide geographic diversity - Greenville 230 kV (selected for high initial MW screening levels, though with higher cost per watt), and the Sutton North 230 kV switching station (relatively low cost per watt but only up to 2,500 MW). After the power flow screening of 32 potential injection sites, the site that stood out for high MW injection capability at relatively lower cost was DEP's New Bern 230 kV substation. New Bern 230 kV substation benefits from already having five 230 kV lines, two of which head in the direction of the DEP Raleigh load center.

Some intervenors mentioned the consideration of other potential POIs such as the Havelock or Greenville 230 kV substations. Table 1 in the 2020 NCTPC Offshore Wind Study Report reveals that the Greenville substation would only be able to accommodate an 1106 MW injection at a cost of $0.38/W, and that the Havelock substation could only accommodate an 859 MW injection, although at a lower cost of $0.02/W. In contrast, the New Bern POI would be able to accommodate 1449 MW at $0.12/W and 3,252 MW at $0.36/W.[28]

Furthermore, upon being studied in an annual official DISIS Cluster Study for generator interconnection, the Greenville and Havelock potential points of interconnection would most likely be shown to require extensive network upgrades to transfer offshore wind from the POI reliably into the DEP system. Additionally, extensive upgrades would most likely be required to transfer offshore wind energy to the corridor for a new 500 kV line needed in order to inject 1,600 MW of offshore wind reliably into the DEP system to transfer to load centers. Looking at Confidential Transmission Panel Exhibit 5 the Havelock substation has three 230 kV lines connecting it to the system with one 230 kV line essentially going to a peninsula (Morehead City). The New Bern substation has five 230 kV lines connecting it to the system, and is thus much more reliable for injecting appreciable offshore wind. The Greenville substation has three 230kV lines connecting it to the DEP system and one 230kV line connecting to PJM's system. It should also be recognized that a submerged cable connecting an offshore wind resource to a Greenville 230 POI would need to traverse the shallow, environmentally sensitive Albemarle

[28] Report on the NCTPC 2020 Offshore Wind Study at 5, Table 2 (Selected Injection Levels at Preferred Sites).

Sound. Furthermore, Greenville is notorious for Tar River flooding with past hurricane events.

VII. TRANSMISSION PLANNING CONSIDERATIONS FOR OFF-SYSTEM PURCHASES

Q. HAS DUKE ENERGY CONDUCTED ANY TRANSMISSION PLANNING ANALYSIS ASSOCIATED WITH INCREASING IMPORT CAPABILITY FOR OFF-SYSTEM PURCHASES?

A. Yes. As discussed in Appendix P, Duke Energy studied a capacity import from PJM.[29] Upon evaluation of previous PJM and DEP feasibility studies and Affected System Studies as well as utilizing the same study tools and PJM queue data, a 1,500 MW transfer was studied from PJM to DEP.

Q. PLEASE DESCRIBE THE RESULTS OF THIS ANALYSIS.

A. The results of this study indicated the need to upgrade transmission facilities in both PJM and DEP with such upgrades requiring significant time and expense. It is estimated that significant system reinforcement projects are needed on both the PJM and DEP transmission systems to enable such import capacity with initial cost estimates starting at approximately $700 million.

Q. HOW DO YOU RESPOND TO THE ASSERTION BY NCSEA, ET AL. AND TECH CUSTOMERS THAT DUKE ENERGY SHOULD FURTHER ANALYZE IMPORTS OF MIDWEST ONSHORE WIND?

A. Duke Energy views access to Midwest onshore wind generation to potentially be acquired by Duke Energy as not being economically feasible at this time. As

[29] Carbon Plan Appendix P at 24.

discussed in Appendix P, Duke analyzed what transmission system upgrades would be needed to import capacity such as Midwest wind and in addition to the significant costs, the duration to complete the identified transmission projects was up to 84 months. To validate the results of this analysis, Duke submitted a 1000MW firm transmission service request ("TSR") to the PJM queue and is awaiting results. The results of this TSR study will be considered in future iterations of the Carbon Plan.

Q. DOES THE CARBON PLAN CONSIDER IMPORTING MIDWEST WIND TO BE POTENTIALLY ACQUIRED BY DUKE ENERGY INTO THE DUKE ENERGY SYSTEM?

A. Yes. The PJM border rate is used for the transmission cost adder for input to consider the Midwest onshore wind resource being imported into the Carolinas.

Q. WHAT WERE THE RESULTS OF THE TRANSMISSION PLANNING ANALYSIS FOR IMPORTING MIDWEST WIND INTO THE DUKE ENERGY SYSTEM?

A. A 2019 feasibility study conducted by PJM for importing 300 MW into DEC reflected extensive upgrades needed on the PJM system at a cost of $411 million with upgrades taking up to 84 months to construct and place into service. Although the source would not be in the same location, this study was used as a proxy to gauge the magnitude and duration for PJM network upgrades to facilitate a Midwest wind purchase. The recent Duke Energy request for a PJM feasibility study for a 1,000 MW transmission service request to import capacity from PJM into the Duke Energy system will provide more current transmission upgrade information for importing PJM system resources such as Midwest onshore wind.

Q. HAVE YOU REVIEWED OTHER PARTIES' RECOMMENDATIONS TO SIGNIFICANTLY INCREASE IMPORTS OF POWER?

A. Yes, I have reviewed comments from the Tech Customers, Synapse for NCSEA, et al., and CCEBA, all of which advocate for the Companies to rely more heavily on off-system purchases and suggest that these purchases are a reliable alternative to new gas generation and future SMRs.

Q. PUTTING ASIDE LEGAL ISSUES REGARDING OWNERSHIP, DO YOU HAVE ANY RESPONSE FROM A TRANSMISSION PERSPECTIVE TO THESE RECOMMENDATIONS?

A. Yes. Reiterating what the Companies communicated to the Commission in the 2020 IRP Technical Conference, the Companies' Resource Adequacy study accounts for nearly 2,000 MW of non-firm assistance from neighboring systems during peak demand periods. Thus, to ensure reliability is maintained or improved while making the generation transition associated with the Carbon Plan, any further off-system resource assistance needs to be in the form of firm capacity. This off-system capacity resource would need a firm transmission service path to meet Duke Energy's designated network resource rules. So three significant actions would need to occur: 1) a firm transmission service reservation would need to be secured on the neighboring system; 2) network transmission service would need to be studied and secured on the Companies' system sinking the capacity; and 3) a firm capacity purchase contract would need to be secured on the neighboring system.

Concerning item 1), Appendix P of the Carbon Plan describes the in-depth analysis that the Companies have conducted to evaluate the potential timeline and associated cost for securing a firm transmission service reservation on the PJM system to accommodate a capacity purchase from the PJM region. No party addresses or refutes this analysis that firm deliverability of power from PJM to DEP would cost $700 million and would take years to become available. Concerning item 2), for any additional imported capacity, the Companies would need to study the potential power flow impacts to identify any necessary transmission network upgrades to support the additional power flow. As stated in Appendix P, the Companies did perform an analysis of a 1500 MW capacity import from PJM and the results of the study indicated the need to upgrade transmission facilities in both PJM and DEP with such upgrades requiring considerable time and expense. Concerning item 3), neighboring systems are also planning to transition their fleets and to retire substantial amounts of coal-fired generation over the next decade.[30] For example, PJM's coal-fired capacity could be cut in half from its current 50 GW of coal-fired generation down to 25 GW by 2030.[31] These neighboring systems are not likely to have excess

[30] North Am. Elec. Reliability Corp., 2021 Long-Term Reliability Assessment at 29 (Dec. 2021), *available at* https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2021.pdf.

[31] Utility Dive, Coal plan owners seek to shut 3.2 GW in PJM in face of economic, regulatory and market pressures (Mar. 22, 2022), *available at* https://www.utilitydive.com/news/coal-plant-owners-seek-to-retire-power-in-pjm/620781/.

capacity resources that the Companies can purchase for delivery to DEC or DEP.

Q. ARE THERE RISKS ASSOCIATED WITH OVER-RELIANCE ON OFF-SYSTEM PURCHASES OF CAPACITY FOR MEETING RESOURCE ADEQUACY NEEDS FROM A TRANSMISSION PERSPECTIVE?

A. Yes. As stated in Appendix P of the Carbon Plan, there are several risks with off-system purchases that must be considered from a reliability perspective. System risks associated with relying on significant incremental off-system capacity purchases for Carbon Plan resource needs include, but are not limited to:

1. Delay in resource availability: If required transmission network upgrades on the DEC/DEP transmission systems or neighboring transmission systems are delayed due to siting, permitting, or construction issues, these delays can jeopardize the scheduled in-service date of the transmission upgrades necessary for importing the capacity resource;
2. Loss of local ancillary benefits that are inherent with an on-system resource (e.g., Voltage/Reactive Support, Inertia/Frequency Response, AGC/Regulation for balancing renewable output) may require more on-system transmission upgrades such as adding static var compensators for voltage support;
3. Curtailment due to transmission constraints in neighboring areas; and

4. Transmission system stability issues under certain scenarios due to added distance between the capacity resource and load.

Furthermore, most off-system purchases are non-dispatchable, which would not benefit integrating variable renewable energy resources.

As discussed in the Reliability Panel Testimony, a high reliance on off-system resources carries substantial reliability risk if the off-system resource cannot deliver the capacity and energy. The August 2020 CAISO firm load shed event[32] and the 2011 Southwest Blackout[33] are both examples of reliability events that can occur due to over-reliance on off-system power purchases and import assistance from neighbors.

VIII. PATH FORWARD ON TRANSMISSION PLANNING FOR ENERGY TRANSITION AND SUCCESSFUL EXECUTION OF CARBON PLAN

Q. PLEASE EXPLAIN WHAT TRANSMISSION PLANNING APPROACHES DUKE ENERGY MUST CONSIDER AND IMPLEMENT FOR THE TRANSMISSION SYSTEM TRANSFORMATION NEEDED TO IMPLEMENT A CARBON PLAN.

A. As stated earlier in this testimony, Duke Energy will need to use an integrated planning approach that adopts proactive transmission planning in order to ensure holistic reliability and economic benefits as we integrate Carbon Plan resources into the power system on a timeline necessary to meet HB 951

[32] California ISO, Final Root Cause Analysis – Mid-August 2020 Extreme Heat Wave (Jan. 13, 2021), *available at* http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf).

[33] Staffs of the Federal Energy Regulatory Commission and the North American Electric Reliability Corporation, Arizona-Southern California Outages on September 8, 2011 – Causes and Recommendations (April 2012), *available at* https://www.nerc.com/pa/rrm/ea/September%2020 11%20Southwest%20Blackout%20Event%20Document%20L/AZOutage_Report_01MAY12.pdf).

requirements. Duke Energy will need to provide comments on the FERC NOPR to ensure a feasible, beneficial pathway for proactive transmission planning is captured in future FERC orders. NOPRs do take a long time to become FERC orders. Any change to Transmission Planning processes will be approved by FERC and would be incorporated into the OATT. The OATT revision process includes steps for stakeholder input.

Furthermore, from a transmission system planning and system risk perspective, we need to be mindful that we cannot un-ring a bell. Our coal-fired generation provides more than just the capacity benefit in a model. Coal-fired generation on the DEC and DEP systems is located near large load centers, provides adverse power flow mitigation, system voltage support, and Nuclear Station Loss of Coolant Accident mitigation voltage support. Retirements of the large coal-fired generators on the Duke Energy system must be carefully planned, including contingency plans that may include retirement delays needed to get transmission upgrades and replacement generation in service to ensure reliability of the system is maintained.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

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

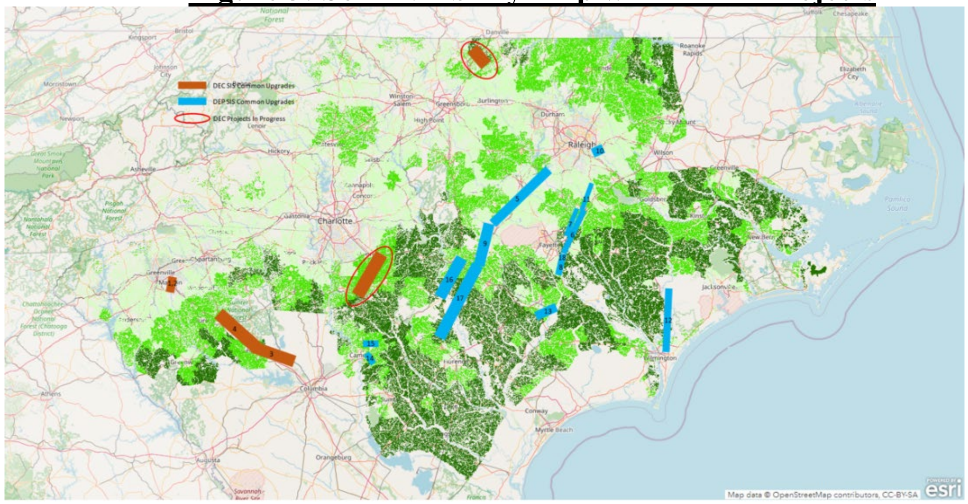
For any plan to meet the HB 951 targets and the energy transition, transmission planning and grid transformation considerations will play a critical role. This Commission recognized the vital role of transmission planning in its final order in the 2020 IRP proceeding. HB 951 also acknowledges the importance of transmission in developing any plan to meet its targets and the energy transition. Our direct testimony builds on the detailed foundation of information included in Appendix P to the Carolinas Carbon Plan, by reintroducing the Companies' local and regional transmission planning and interconnection processes. In addition, our direct testimony identifies and supports several key transmission-related points for the Commission's consideration.

By setting the carbon reduction targets, HB 951 establishes new public policy goals that require the Companies to add new generation and other resources to their systems at an incredible speed. Duke Energy also plans to retire significant amounts of coal generation as part of its transition to a cleaner energy future. An effective transmission planning process is necessary to ensure system adequacy and reliability as the Companies navigate these changes. The Companies are therefore requesting that the Commission direct Duke Energy to continue to study future transmission needs to reliably implement the Carbon Plan, primarily through the FERC-approved North Carolina Transmission Planning Collaborative – or "NCTPC" – local planning process.

The Companies support transitioning to a more proactive transmission planning process that is better integrated with resource planning. Integrating resource planning with a proactive transmission planning approach will help to overcome the challenges associated with scaling up clean energy resources in the Companies' systems in a timely manner and thus mitigate energy transition and Carbon Plan execution risk.

Proactively planning and constructing the Red Zone Expansion Plan – or "RZEP" – projects are a necessary first step in executing the energy transition and the Carbon Plan in a least-cost manner. Figure 3 of our direct testimony shows that the RZEP projects are located in high solar viability areas – those areas of the Company's service territories that are well-suited to large utility-scaled solar generation as evidenced by the volume of historical solar interconnection requests in these locations.

Figure 3: Solar Viability Map with RZEP Projects



The Companies have repeatedly identified these projects through generator interconnection studies as solutions to transmission constraints that have impeded solar interconnections in the red zones. In addition, over 64% of 2022 DISIS solar facilities as shown in Figure 2 of the Direct Testimony and 70% of the proposals received in the recent bid window for the 2022 Solar Procurement as shown in Figure 4 of the Direct Testimony are requesting interconnection in the red zones.

Figure 2: 2022 DISIS Red-Zone Map

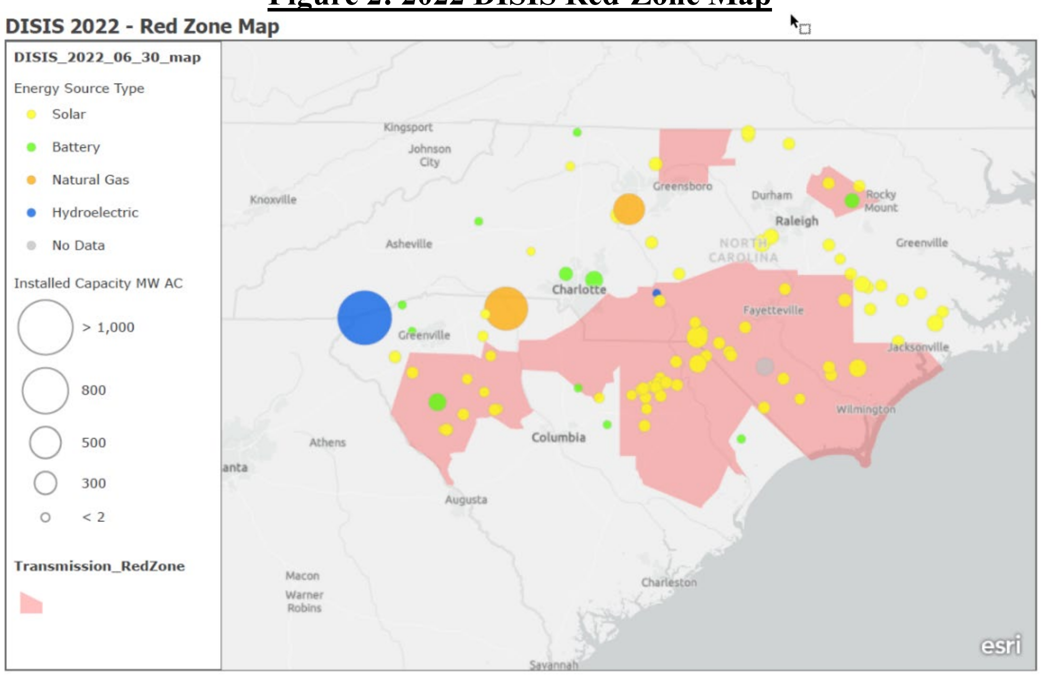
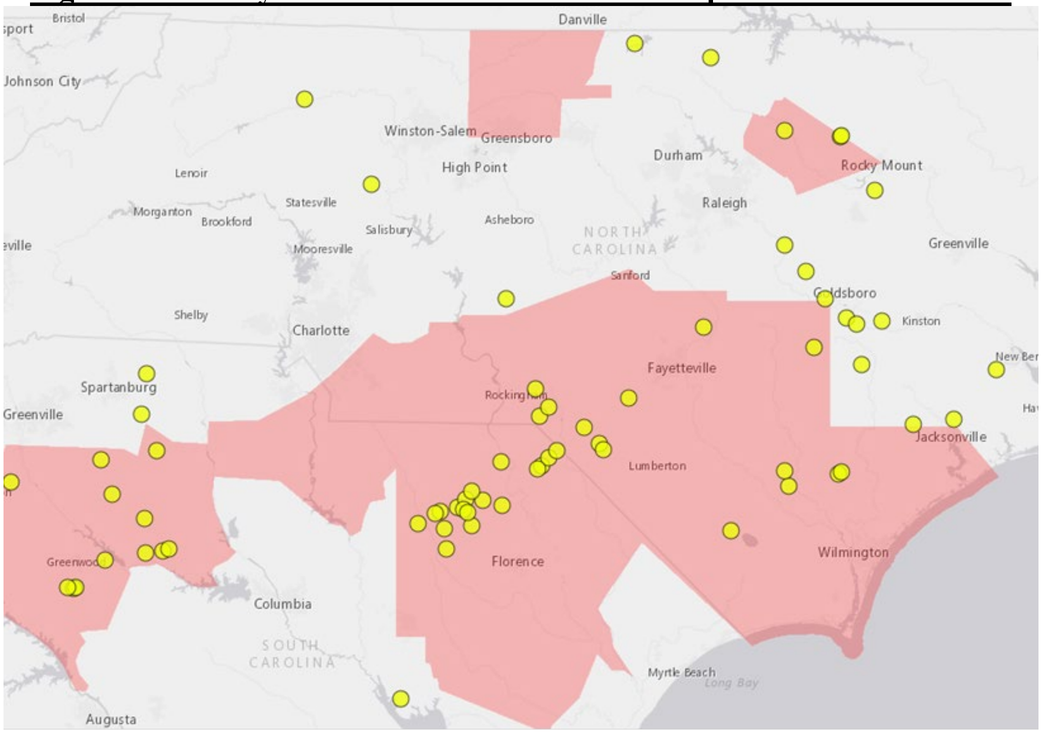


Figure 4: Overlay of 2022 Solar Procurement Proposals with Red Zones



Subsequently to filing the Plan, the Companies performed supplemental planning studies to further evaluate the need for the RZEP projects. The results of these studies reinforce the need for the majority of these projects in order to integrate future generation and to successfully execute the Carbon Plan. Based on these historical and recent studies, the Companies request Commission acknowledgement that these projects are needed to interconnect new solar generation and meet the HB 951 targets. The Commission's acknowledgement will provide strong evidence to the NCTPC that approval of the RZEP projects as part of a local transmission plan is reasonable and prudent.

With regard to the cost for the RZEP projects, the Companies estimated transmission network upgrade costs as an input for selecting resources for the Carbon Plan portfolios. These dollar per watt cost proxies were derived primarily from the most recent, available historical generator interconnection studies. In this way, the Carbon Plan reasonably integrates transmission costs associated with the energy transition into the resource planning analysis.

Our testimony also addresses the Companies' ongoing planning for retiring existing coal facilities that support the grid and integrating incremental resources forecasted in the Carbon Plan resource portfolios that will require significant investment in the DEC and DEP transmission systems. The Companies are pursuing approval of a generator replacement process to enable more efficient and cost-effective interconnection of generating facilities at existing sites. Replacing retiring generation with new generation that is on-site and connected to the same electrical point of interconnection will create substantial efficiencies and cost savings for customers by avoiding the need for significant transmission upgrades.

Based on the 2020 NCTPC Offshore Wind Study and additional Duke Energy cost analysis, the New Bern point of interconnection is the most appropriate location to import up to 1,600 MW of offshore wind into the DEP system, based on cost effectiveness, reliability, and interconnectivity. Duke Energy's analysis shows that the New Bern point of interconnection would be more cost-effective compared to other potential points of interconnection, would allow the Companies to utilize existing right-of-way for the network transmission, and will reduce risk and cost for an offshore wind project through planning for network and radial transmission in a comprehensive manner for the project.

From a transmission planning and operations perspective, assuming the Companies can rely upon significant incremental off-system capacity purchases as a Carbon Plan resource would present both increased costs and risks to the system. For example, a Duke Energy analysis showed that increasing import capability to allow for a 1,500 MW transfer from PJM to DEP would require upgrades to transmission facilities that would involve significant time and expense. To further validate these time and expense concerns, the Companies have submitted a transmission service request to PJM to study a 1000 MW import of capacity from PJM. The results of this PJM study should be further inform transmission cost and timing inputs for making a decision on the feasibility of a capacity import from PJM.

In conclusion, the momentous shift in the generating fleet expected to occur in the next few years will require a significant build-out of the transmission system to support reliable operations, ensure generator deliverability for a changing resource portfolio, and economically serve changing customer demand. Duke Energy will need to use an integrated planning approach that adopts proactive transmission planning and pursues the RZEP projects in order to ensure holistic reliability and economic benefits as we integrate Carbon Plan resources into the power system on a timeline necessary to meet HB 951 targets. The Companies' requests to the Commission with respect to transmission planning and grid transformation will help pave the way for successful execution of the Carbon Plan and energy transition in the near-term in a least cost and reliable manner.

MS. KELLS: And I also ask that the panel's five exhibits be marked for identification as prefiled with the Direct Exhibit 5 marked as confidential.

CHAIR MITCHELL: All right. Hearing no objection, exhibits to the testimony will be marked as they were when prefiled with Exhibit 5 being identified as confidential.

MS. KELLS: Thank you.

(Transmission Panel Exhibits 1 through 4 and Confidential Transmission Panel Exhibit 5 were identified as they were marked when prefiled.)

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

CHAIR MITCHELL: All right. Let's see, who is up first?

MR. SMITH: I believe Avengrid's up first.

CHAIR MITCHELL: All right. Go ahead, proceed.

CROSS EXAMINATION BY MR. SMITH:

Q. Hello, my name is Ben Smith. I represent

Avengrid Rewewables, LLC. I'm gonna be asking the Transmission Panel some questions about offshore wind issues. Mr. Roberts, I believe most of those are directed to you, but I apologize if one of them goes to you, Ms. Farver, please jump in.

On page 56 of your direct testimony, and it's approximately line 16 or so.

A. (Sammy Roberts) Yes.

Q. You state agreement with the findings of the North Carolina Transmission Planning Collaborative showing that the New Bern area could accommodate more than 3 gigawatts of offshore wind.

This assumption -- this assumes the build-out of a 500 kV expansion, correct?

A. That is correct.

Q. Okay. Would it be fair to say the most cost-effective transmission solution for the first offshore wind project would be to fully maximize the existing system without triggering 500 kV upgrades?

A. So you got to take the NCTPC offshore wind study in context. There's some stipulations that are mentioned at the beginning of the study that should be known. One of those is that it mentions that generators requesting interconnection in queues that may connect are not considered in the study. So that's one stipulation. The other stipulation is that, with the dispatch that was used, with respect to the screening that was done by that study, it didn't look at any max gen scenarios; i.e., ensuring that existing generators that have interim service can still deliver their firm output.

Q. So just to be clear, your response to "would it be fair to say that the most cost-effective transmission solution for first offshore wind project would be to fully maximize the existing system without triggering 500 kV upgrades" is that NCTPC study does not fully characterize -- or does not fully give information that could lead you to that conclusion?

A. See, you also had to take into context -- and this is the whole idea behind proactive transmission that's mentioned in my testimony. You had to take into context the holistic story. What are you going to be doing in the future with respect to meeting this carbon reduction objective? And one of the things that you had to take into consideration with offshore wind is scale, right?

So you want to plan for scale if you're looking at potentially increasing to 1-and-a-half gigawatts to 2 gigawatts to 2-and-a-half gigawatts, you need to plan for that with your transmission system. I think the Public Staff mentions that with respect to not wanting to be faced with upgrading the upgrade, so to speak, down the road.

Q. Understood.

MR. SMITH: Well, with that, I'd like to introduce the 2020 NCTPC offshore wind study and present to the witnesses for review and then mark as an exhibit.

(Pause.)

CHAIR MITCHELL: If you-all would pull the mics a little bit closer just so the court reporter can hear you, thank you. She's having trouble at this point. All right. Let's go ahead and get this document marked, please.

MR. SMITH: I'd request this be marked Avengrid Renewables, LLC Transmission Panel Cross Examination Exhibit Number 1.

CHAIR MITCHELL: So the document will be marked as Avengrid Transmission Panel Direct Cross Examination Exhibit 1.

(Avengrid Transmission Panel Direct Cross Examination Exhibit 1 was marked for identification.)

MR. SMITH: And, Chair, we omitted the word Direct Transmission Panel. It should say Transmission Panel Direct Cross Examination Exhibit 1. Co-counsel just noticed, so apologies for that.

Q. Mr. Roberts, do you recognize this document?

A. (Sammy Roberts) Yes, I do.

Q. And would you agree this is a copy of the 2020 NCTPC offshore wind study, the same study you relied upon you in your direct testimony?

A. I haven't looked through all the pages, but I'll take your word for it.

Q. Yeah. Okay. Subject to check. I'd like to direct you first to the bottom of page 18 of the report within Appendix A.1.

A. (Witness peruses document.)

Page 18?

Q. Yes, sir.

A. (Witness peruses document.)

Q. And I'd like to point to the results for the 32 injection sites without kV -- 500 kV additions, the last row highlighted in green on this page; do you see that?

A. Yes.
Q. And do you recognize that finding in the study, that New Bern could support more than 1.7 gigawatts without building a 500 kV expansion?
A. So once again, this was a screening study, and it did not look at the consideration for additional resources to be located in areas that affected these power flows. And it did not consider max gen scenarios to ensure firm deliverability of existing resources. But yes, you're correct, it shows 1,773 associated with the New Bern site.
Q. Assuming that the right number for coming on ground is 1.3 gigawatts, for example, how much less would project spend on transmission upgrades be versus the 500 kV system expansion modeled by Duke for 1.6 gigawatts of offshore wind?
A. I don't know what the number would be. I'll just state that, if you're looking at 1.3 gigawatts, the only way to truly tell what the network upgrades are going to be is to perform a -- get an interconnection request into the DISIS study. Because once again, you can have additional generation that connects between now and then that could greatly impact -- and that's what the study says -- can greatly

impact the power flows associated with how much you can inject into that area.

And I'll give you an example. And I stated this in the -- I think it was the third stakeholder meeting in March. Anyway, I stated that you're gonna have significant solar connecting to the system, and you've got to consider sequence. If that solar connects to the system and impacts those power flows in that area prior to that offshore wind interconnecting, the network upgrades can be drastically different.

Q. Thank you. Would it be fair to say that the number of total megawatts that would be triggered would be somewhere between the 500 megawatts modeled by Duke in the blocks -- I'm sorry, excuse me, 800 megawatts modeled by Duke in their blocks, but less than the 1.7 gigawatts in the NCTP [sic] study which would be deliverable without that 500 kV upgrade?

A. I mean, once again, I can't say that for sure unless a formal DISIS interconnection study, cluster study is performed. I can't definitively say that. I mean, we can provide input to modeling on our review and, you know, what -- what network upgrades are associated with that.

Q. Sure. I'd like to point you to Appendix A.2

of the NCTPC study on page 21.

A. (Witness peruses document.)

Okay.

Q. On page 21, in the seventh row from the bottom, if you could find that. On the far right, in the incremental cost column, there is the number 570.

Do you recognize that to be 570 million?

A. (Witness peruses document.)

I'm sorry, I must be on the wrong place. You said page 21?

Q. Page 21.

A. And seventh from the bottom?

Q. I'm sorry, sixth from the bottom, I believe. Fifth from the bottom. My eyes are playing tricks on me.

A. Okay. Fifth from the bottom. Yes, I see 570 million incremental cost.

Q. Would it be fair to say that that 570 million reflects the cost upgrades associated with that 500 kV system upgrade?

A. Per this report, yes.

Q. Thank you. So based on the NCTPC study, you could get more than 1 gigawatt -- I proposed about 1.3 gigawatts -- delivered for a similar cost as Duke modeled for the first 800-megawatt blocks; isn't that right?

A. That's apples and oranges. I mean, once again, there's things this report or this study didn't consider that would need to be considered in a true DISIS cluster study for interconnection.

Q. So wouldn't it be appropriate, then, to do a cost benefit analysis of any transmission upgrade for new offshore wind to reflect optimal output capabilities rather than what Duke's done in modeling in, quote, unquote, average size block not reflecting real-world capabilities or costs?

A. Yeah. So we -- I mean, we looked at several interconnections -- potential points of interconnection, and through the cost analysis associated with that, those different points of interconnections, a given level of megawatts of offshore wind, New Bern was the cheapest.

Q. Thanks. I've only got a few more. Going to page 17 of the study.

A. Okay.

Q. The second line of the Havelock point of interconnection, which is marked -- it's actually the third in the Havelock listing, on the far left POI.

Do you see that?

A. Yes.

Q. Okay. Do you see the second column, megawatt limit, and there's 1,001 listed for that?

A. Yes. The last unhighlighted line shows 1,001-megawatt limit.

Q. And do you recognize that to say that the study is showing that the Havelock point of interconnection can accommodate 1,001 megawatts?

A. With the limitations aforementioned about the study, yes, this table does show a 1,001-megawatt limit for Havelock.

Q. So wouldn't you agree that, at least based upon this study, that the Havelock point of interconnection accommodates more than 1 gigawatt with -- relative to other cost upgrades, lower cost upgrades, and those cost upgrades are less than Duke's modeling assumptions?

A. Once again, I can't agree to your statement without having a true cluster study done.

Q. And I guess I'll ask it this way, then.

Has Duke completed any studies that refute these numbers where I say the Havelock costs would be lower than New Bern upgrades?

A. Yeah. So for the four points of interconnection, one thing you got to know about Havelock is it only has three 230 kV lines connecting to it. One goes due east to kind of a peninsula, which is Morehead; the other one goes due south to Jacksonville, in which you've got over 2,600 megawatts of generation just to the south with our Brunswick nuclear station and Sutton plant; and then you've got a loin going to the northwest toward New Bern, 230 kV line out of Havelock.

And so one of the things you have to look at in any good interconnection study is the loss of that New Bern to Havelock 230 line. Where is that power gonna go; what's gonna -- can't all go toward Morehead's peninsula. It's gonna try to go toward Brunswick and Sutton. Well, you've got all that power trying to come up north from Brunswick and Sutton.

And so it's -- you're gonna need some extensive upgrades out of Havelock to be able to inject any amount of offshore wind. And it's not gonna be as reliable as New Bern where you have 230 kV lines, two of which go directly toward Raleigh, which is a big load center.

Q. Thank you. I guess my last question is, what studies has Duke done that have been presented to the Commission or otherwise publicly that sort of talk about the optimal way to incorporate any of the three wind leased areas off the coast of North Carolina?

A. Yeah. So we haven't conducted studies with respect to the three wind leased areas off the coast of North Carolina. No formal analysis has been done. That's what I'm saying, you need a DISIS cluster study with knowing what generators are requesting interconnection in that DISIS cluster to get a true picture associated with what upgrades are going to be actually needed.

And so, you know, to your point earlier of injecting 1,000 megawatts into Havelock, that's not gonna be possible knowing about all the solar, just in the 2022 DISIS that's requesting interconnection along that corridor going toward Raleigh from that area.

Q. But you agree -- you would agree that the reason for me bringing up more than 1 gigawatt in Havelock is based upon this 2020 North Carolina transmission planning collaborative study, correct?

MS. KELLS: Objection. Witness can't speak to Counsel's motivations.

CHAIR MITCHELL: All right. I'll

sustain. Mr. Smith, just restate the question.

MR. SMITH: I can restate it.

Q. You'd agree that there aren't any other studies that have been filed with this Commission or otherwise out in the public domain that would show the insider knowledge that you talked about right there when you're talking about considering solar and considering offshore wind coming in at somewhere like Havelock?

A. That's correct. There is no formal DISIS cluster study that's been produced, results that's been produced associated with offshore wind being injected into New Bern or Havelock or Greenport or otherwise.

Q. And are you aware of any informal studies?

A. We performed some informal analysis associated with injecting offshore wind into New Bern.

Q. No further questions.

CHAIR MITCHELL: All right. Mr. Burns?

CROSS EXAMINATION BY MR. BURNS:

Q. Hi, this is John Burns with CCEBA. It's a pleasure to meet both of you. I just have questions on two main topics, and then I'll move on to let someone else ask you questions.

Ms. Farver, earlier in this hearing, I

discussed the status of contract documents for PPAs for solar plus storage with Mr. Kalemba, and he deferred the questions to you.

Would you agree with that panel that the status of those documents is within your area of knowledge and expertise?

MS. KELLS: I'm gonna object just real quick, because this is handled in Ms. Farver's rebuttal testimony. We recognize the Modeling Panel addressed it, but we're prepared to handle it on -- there'll be ample chance to address it on rebuttal. It's not discussed in direct at all.

MR. BURNS: I was just following up on questions I intended to ask the Modeling Panel on direct, but -- and they deferred directly to this panel. So it's only a few, but I can pick it up at rebuttal or I can do it now.

CHAIR MITCHELL: I'm gonna overrule and let you ask it now. Just be mindful of -- eliminate duplication on rebuttal, please.

MR. BURNS: Absolutely. Will do.

Q. In that light, I will show you a document that I will identify as CCEBA Transmission Panel Direct Cross Exhibit 1, which is the response to CPSA Data

Request Number 3-10.

CHAIR MITCHELL: We're short one, actually.

MR. BURNS: That's why I went to law school and not engineering school. I ask the Chair to mark that as CCEBA Transmission Panel Direct Cross Exhibit 1.

CHAIR MITCHELL: Okay. The document will be marked as CPSA Transmission Panel Direct Cross Examination Exhibit 1.

MR. BURNS: Madam Chair, may I gently correct, it's CCEBA Transmission Panel.

CHAIR MITCHELL: I'm sorry.

MR. BURNS: That's okay.

CHAIR MITCHELL: CCEBA Transmission Panel Direct Cross Examination Exhibit 1.

MR. BURNS: Yes, ma'am.

(CCEBA Transmission Panel Direct Cross Examination Exhibit 1 was marked for identification.)

Q. Now, it is a CPSA data request.

Do you recognize that document, Ms. Farver?

A. (Maura Farver) I do. I'm generally familiar with it.

Q. Okay. In response to this data request, which asked to identify the status of those contracts, please describe in detail all work performed or commissioned by the Companies to devise contract structures of the type described in the cited testimony. Duke responded, and I'll ask you to take a look. I don't have my highlighted page anymore, so I have to find my spot.

In the second line of the response, notwithstanding the objections, stated, "To date, the Companies have not developed alternative contract structures that would enable the flexibility and operational control of the SPS resource as modeled in the Carbon Plan."

Do you see that?

A. I do.

Q. Do you agree with that response?

A. That's correct.

Q. Okay. It's important to develop contracts for the procurement of solar plus storage that allow operational control, isn't it?

A. That's correct.

Q. And that would include dispatchability and allowing the utility to determine the timing and use of that storage asset; is that right?

A. Yes, that's correct.

Q. It's true, isn't it, that the storage element of a hybrid solar plus storage system has more and more flexible uses than the solar portion of a hybrid system?

A. It can.

Q. All right. So it's not just megawatts at a given moment in time; it can be used for load balancing, correct?

A. Depending on the functions, the design, the contract structure, it can.

Q. Time shifting of delivery of the power is --

A. It can.

Q. Okay. And perhaps even reducing the burden on constrained transmission during certain times of the day; is that right?

A. That is possible.

Q. Okay. Are you familiar with the language of House Bill 951?

A. Yes, generally.

Q. All right. In Section 1, sub 2B of that bill it says that solar energy procured under HB 951 shall allow the procuring electric public utility rights to dispatch, operate, and control the solicited solar energy facilities in the same manner as the utility's own generating resources; do you recall that?

A. I do.

MS. KELLS: Can you put the --

MR. BURNS: It's just a reference to the statute. I'm happy to put it in front of her, but I think she agrees with it.

A. Subject to check, yes.

Q. Thank you. And that those ownership requirements shall be applicable to solar energy facilities paired with storage, right?

A. Subject to check, yes.

Q. Thank you. Would you agree with me, Ms. Farver, that contracting partners of the Companies generally provide services and assets in exchange for payment from the Companies?

A. I believe so.

Q. All right. And it's true that storage capacity is not free, right?

A. I would not think so.

Q. There is capital costs incurred in the construction of a storage facility or a hybrid solar plus storage facility?

A. I would assume so.

Q. And if Duke is to obtain services for a solar plus storage, it should compensate the developers or the owners of those facilities for the use of the storage facilities as well?

A. Appropriately for the value it provides, yes.

Q. Thank you. What process do the Companies intend to pursue in order to develop those contract terms and documents?

A. First and foremost, I think we're looking at having stakeholder engagement probably later this year. When we were developing the 2022 solar procurement, part of the reason that we did not include solar plus storage was because we recognize there would be complexity in trying to establish new contract types.

We're trying to move very quickly to get the '22 procurement off the ground, and so we did commit to having further stakeholder discussions in preparations for a future 2023 RFP. So I think we will really start with stakeholder meetings and feedback from participants in those meetings.

Q. Do you anticipate that as part of the 2023 procurement process or do you anticipate that being a separate docket?

A. At this point, I haven't contemplated what the appropriate docket is for such stakeholder meetings or if a docket is necessary. Haven't gotten that far in the planning, but we do intend to have those meeting.

Q. Would you agree that the input of the solar plus storage development community is key to the outcome of that process?

A. I think the solar and solar plus storage community have been very active participants in all of our stakeholder meetings and will continue to be.

Q. I'd like to change -- thank you very much. I'd like to change subjects now to transmission planning. And, Mr. Roberts, I believe this is your area of expertise, but, Ms. Farver, if you have the answer to any of these questions, please feel free to jump in.

In your testimony you stress, quote, the importance of integrating transmission planning with resource planning and the need for proactive transmission planning. And that occurs in a couple of places on page 6 of your testimony, lines 11, 12, and then a couple times on 14 and 16.

Would you agree that it's important to

integrate transmission planning with resource planning?
A. (Sammy Roberts) Yes.
Q. And it's important to have proactive transmission planning as part of the Carbon Plan process?
A. Yes.
Q. And I believe it's your testimony on page 17, lines 1 through 6. Are you there?
A. Yes.
Q. Okay. If the transmission and planning and resource planning processes are misaligned, leading to insufficient transmission development on a timely basis, the lack of transmission infrastructure to reliably support coal retirements and integrate significant amounts of new generation puts Carbon Plan and energy transition execution at risk.
Is that your testimony?
A. That's correct. Transmission planning would just be one of the factors that you would need.
Q. And is it true that integration of resource planning and transmission planning can help to mitigate that execution risk?
A. Yes.
Q. Could it also reduce the cost of any upgrades

that are required?
A. Yes. I mean, that's pretty widely known, that proactive transmission planning in the state of one or two intervenors results in lower cost.
Q. Okay. Would you agree with me that the current local transmission planning process through the NCTPC is insufficient to meet the needs and risks posed by execution of the Carbon Plan?
A. I would not say it's insufficient. I would say we need to look at what the current processes are that are in place and maybe refine some of those processes.
Q. In your testimony on page 18, you have a chart there at the top, and you state that the current interconnection process requires an approximately two-in-one-quarter-year period from the time the interconnection request is made to the time an interconnection agreement is signed; is that right?
A. That's correct.
Q. And then on page 18, line 13, you describe the current process as a reactive generator interconnection driven approach?
A. That's correct. I mean, you submit a generator interconnection request and it goes through

the process demonstrated by this Gantt chart. And then two, two-and-a-quarter years later, you receive an interconnection agreement.

Q. And following that process, you state in your testimony, will create significant timeline challenges, right?

A. That process and the associated network upgrades that could be attributed to the resource requesting interconnection.

Q. Right, well at a high level, because it's not -- I'll speak for myself. I had trouble identifying exactly what the Company wanted to do as proactive transmission planning reform.

How would you describe what Duke Energy wishes to do with the local transmission planning process?

A. Yeah. So as mentioned with the NCTPC wind study, one of the things we would want to look at is to have the studies be more like a true generator interconnection study. And so thus the results that you have from the study in the report would more -- be more reflective of real life. Now, you still would have the caveat of that study wouldn't know what's actually going to interconnect, if it's in the current queue or maybe even future queues.

And so that would be something we would need to address as well. But that and, you know, looking out longer term with respect to having a holistic solution associated with the transmission planning process.

Q. Thank you. On page 65 of your testimony, lines 1 through 6 --

A. 65, 1 through 6?

Q. Yes.

A. Okay. I'm there.

Q. You state that Duke Energy will need to provide comments on the FERC NOPR to ensure a feasible beneficial pathway for proactive transmission planning is captured in future FERC orders. And then you state that any change to transmission planning processes will be approved by FERC and would be incorporated to the OATT.

What's the OATT, just for the record?

A. Sorry. Open access transmission tariff.

Q. And the open access transmission tariff revision process includes steps for stakeholder input.

Did I recite your testimony correctly?

A. Yes, you did.

Q. I read that testimony to suggest that any change to transmission planning should wait until after the FERC issues an order on the pending NOPR.

Am I right on that?

A. So there are -- there are things like changing to more of a generator interconnection-type study in the NCTPC process that we could implement without needing a FERC order or FERC approval.

Q. It could take a couple of years for the NOPR order to be finalized, couldn't it?

A. It could.

Q. To be clear, most of the changes proposed in the FERC NOPR relate to the regional transmission planning process, correct?

A. That's correct, but there are some implications toward local transmission planning as well.

Q. What would the Commission's role in local transmission planning be under your -- under Duke's concept?

A. This Commission?

Q. Uh-huh.

A. Yeah. So, I mean, through orders 890, order 1000 and subsequent order like you're referring to with the NOPR, we would have to implement what the FERC -- what's in the FERC order, just like with 890 and order 1000. I know that there are participants on this Commission with the FERC NARUC task force, and they're closely following the NOPR as well, transmission planning NOPR.

And so I'm sure that that's an avenue for input. I've seen that a person on the Public Staff is engaging in panel conversation associated with these transmission planning processes. So I'm sure, through that input, their voice will be heard with respect to the final outcome of the FERC order.

Q. On page -- thank you. On page 40 of your testimony, you are asked at the top of the page -- I'll wait for you to get there. Are you caught up with me?

A. Yes.

Q. "The Public Staff and other parties suggest that the NCTPC planning process also needs to evolve to meet the evolving needs of executing the Carbon Plan. Do the Companies agree?"

Your answer is yes, right?

A. Yes.

Q. And that the Companies will work with other NCTPC OSC members and stakeholders to consider changes to the local transmission planning processes to improve coordination with Carbon Plan execution and ensure timely and robust review of transmission projects necessary to meet anticipated generation needs.

The OSC is the steering committee of the NCTPC, correct?

A. That's correct. The Oversight Steering Committee.

Q. Who are the members of the Oversight Steering Committee?

A. Currently the members are the load-serving entities and basically the network demand. That's whose gonna ultimately fund or pay for transmission assets, new transmission assets. And so rightly so, it's Duke Energy Carolinas, Duke Energy Progress, Electricities, and NCMC.

Q. Okay. And there's no -- there's no role for third-party developers or providers or sellers of power on the OSC, correct?

A. On the OSC, that's correct.

Q. And there's no rule -- there's no role for customers and end consumers on the OSC, correct?

A. Right. Those roles are facilitated through the -- what's called the Transmission Advisory Group, which is a stakeholder group. And that's required by the FERC process.

Q. Now, the NCTPC doesn't have any role in resource planning, does it?

A. Indirectly, yes. I mean, one of the functions is associated with transmission planning for generation additions. I mean, that's stated in every annual local transmission plan report.

Q. But you don't -- Duke doesn't run its IRP or its Carbon Plan by the NCTPC for approval before submitting it to this Commission?

A. We take the changes as projected by the IRP; i.e., coal retirements. And those are in the reliability base plan at NCTPC.

Q. Just a couple more questions.

To clarify, does the Company -- the Company does intend to fully engage stakeholders, other than just the OSC members, regarding changes to the local transmission planning process, doesn't it?

A. I mean, there's nothing prohibiting us from including TAG conversations and meetings associated with the refinements to our process. Now, there are some things that we cannot change unless it's approved by FERC, and that's anything that's in our OATT that's restrictive about this process.

Q. And that would be the notice requirements to the public and to members of TAG; that's among the things that couldn't change, right?

A. That's correct. I mean, you've got to have the stakeholder agree.

Q. Okay. And as we said, currently the TAG only has an advisory role in the TPC process, correct?

A. The TAG can suggest alternate solutions, provide input. And, I mean, we received a lot of TAG input from stakeholders with respect to the midyear update presentation that we provide.

Q. Sure. I appreciate that. TAG numbers can request studies; is that right?

A. That's correct. Through the forum of, like, a public policy request, they can request the study.

Q. And if a TAG member makes more than three such requests, they have to pay the cost of that further study on their own; isn't that right?

A. That's the current capability of the NCTPC.

Q. Okay. Does Duke plan to engage other stakeholders, outside the OSC, in anything more than the advisory capacity current played by TAG?

A. I mean, currently the structure is what's filed in the OATT and approved by FERC.

Q. Give me just one minute, I may be done. No further questions at this time. Thank you.

CHAIR MITCHELL: All right. CIGFUR?

MS. CRESS: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MS. CRESS:

Q. Good afternoon, Ms. Farver and Mr. Roberts. I am going to start by asking you a couple of questions about an exhibit that's already been admitted into the record when I was asking your colleagues on the Modeling Panel some questions. And that panel ended up essentially largely deferring to this panel in response, and so I wanted to circle back to it. It's CIGFUR II and III --

MS. KELLS: Do you have copies -- does counsel have additional copies since this panel wasn't present in the room?

MS. CRESS: I have a copy for the witnesses that I'm happy to provide in a moment. But it's CIGFUR II and III Modeling Panel Direct Commissioner Questions Exhibit Number 1. And it is Duke's response to Public Staff Data Request 5-13. And I'll ask my colleague here to bring this up to you in just a moment, but then I won't have a copy, so give me -- give me one moment if you will. But -- oh.

MR. BREITSCHWERDT: I've got a copy I can share with the witnesses.

MS. CRESS: Thank you.

Q. Okay. Mr. Roberts, can you please confirm that this data request is stating that the Company has not updated the transmission cost adder in the Carbon Plan to align with the approximately $7 billion upgrade estimate from the hypothetical transmission build-out?

A. (Sammy Roberts) Yes. So -- but there's reasons for that. I mean, that -- what was presented in the stakeholder meeting and what's presented in the figure in Appendix P associated with this hypothetical example, it would really be imprudent to incorporate those costs.

Q. Why is that?

A. It's a hypothetical example. It's -- I mean, there --

CHAIR MITCHELL: Mr. Roberts, make sure you're speaking into the mic for us, please.

THE WITNESS: Sorry. It was a -- it is a hypothetical example of a long-range transmission plan, and things where generators are sited may be drastically different in the next Carbon Plan with the projected, and that would result in a totally different long-range transmission plan.

And so furthermore, with the baseline costs that were included -- and I'll refer to Table E-44 in Appendix E of the Carbon Plan -- those baseline cost proxies are escalated in time to reflect inflation. And so that's gonna capture a lot of the future ongoing transmission upgrade costs associated with interconnecting resources.

Q. So just to confirm, the transmission cost adder is also something that Duke is going to be deploying the check-and-adjust strategy for? In other words, coming back in 2024 --

A. Yes.

Q. -- and updating it?

A. Yes. So this Commission did request -- directed us to upgrade these costs in the 2020 IRP order. Pardon me, but I don't remember, I think it was November of '21 when that came out. But anyway, in that order, it directed us to update these proxy costs or network upgrades. And we did that for this Carbon Plan. And we will continue to do that for each Carbon Plan.

Q. Did the 2020 IRP portfolio that was selected include build-out of offshore wind?

A. So there -- in the 2020 IRP, there were six portfolios, and pardon me, but this was not part of my direct testimony, but from what I recall, three -- I think it was three of those six portfolios had offshore wind.

Q. And what about the portfolios selected?

A. I don't recall the portfolio that was selected in the 2020 IRP. I don't believe there was a portfolio selected. I don't recall.

Q. Thank you.

MS. CRESS: At this time, I will ask for assistance passing out our next exhibit. I guess it will be the first one for this panel. This is Duke's response to Public Staff Data Request 5-21, which CIGFUR II and III will ask be marked for identification as CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit Number 1.

CHAIR MITCHELL: All right. The document will be marked CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit 1.

MS. CRESS: Thank you, Chair Mitchell.

(CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit 1 was marked for identification.)

Q. Mr. Roberts, I'm gonna direct your attention to subpart E of this data request.

A. (Witness peruses document.)

Q. And you were the designated responder for the Company for subpart E; is that correct?

A. (Witness peruses document.)

I don't believe so. Oh, I see, you're on a different E than I'm on. Sorry.

Q. So I'll ask again. You were the responder for the Company for subpart E of this data request?

A. Yes, that's correct.

Q. Okay. And is this response addressing Rule R-862; it's specifically CECPCN regulatory requirements?

A. Yes, that's correct.

Q. Okay. And can you please talk about the request for regulatory changes to that process that the Companies are requesting?

A. Yeah. Can you give me a minute to re-read the response?

Q. Sure. Absolutely. Thanks.

A. (Witness peruses document.)
Okay.
Q. So I'll ask the question again.
Can you speak to any changes that the Companies are seeking to this regulatory process?
MS. KELLS: Objection. Can counsel be more specific as to if she's speaking to a particular -- to the rule in terms of the regulatory process?
MS. CRESS: I mean, Chair Mitchell, I would say that the witness can answer the question, and if he can't or needs clarification, he's free to say that.
THE WITNESS: I mean, it's talking about --
CHAIR MITCHELL: Hang on, Mr. Roberts. Ms. Cress, I'm gonna sustain the objection. Ask your question again, but just with more specificity so that the answer can -- the witness can answer efficiently.
Q. Is there anything about the siting process or the certification process before this Commission for a new transmission facility that the Companies are seeking to change or expedite in the context of Carbon

Plan investments?

A. Yeah. I mean, typically, siting and permitting do introduce potential delays associated with new transmission. And so to the extent that those delays can be reduced, that would be beneficial to executing the Carbon Plan.

Q. You acknowledge, though, that any, you know, approval in a Carbon Plan process would not be a replacement or a substitute for a CECPCN proceeding, correct?

MS. KELLS: I object to the extent it's asking for a legal opinion.

MS. CRESS: Chair Mitchell, he provides a legal opinion himself, then, if that's the standard we're using here. He says, "To the extent a solar facility or another resource is selected as needed in the Carbon Plan, this selection provides indicia of the public convenience and necessity required to support construction of any required transmission facilities."

CHAIR MITCHELL: All right. Ms. Cress, where are you reading from? Which page?

MS. CRESS: The last page of this exhibit, subpart E, the second paragraph, second sentence.

CHAIR MITCHELL: All right. I'm gonna overrule the objection. Mr. Roberts, to the extent that you have anything to add to this response, please do so.

THE WITNESS: Yeah. I mean, basically, with the Commission's approval of a Carbon Plan and resource such as a solar facility, once again, with new transmission line siting, that would require the CPCN, or if you have to acquire right of way. And so, I mean, this is just talking about expediting that process.

Q. Are we talking about CPCNs or CECPN?

A. CECPN, sorry.

Q. Okay. Thank you. Okay. Moving on. I'm gonna show you Duke's response to Public Staff Data Request 5-16.

MS. CRESS: Which I'll request be marked for identification as CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit Number 2.

CHAIR MITCHELL: All right. The document will be marked CIGFUR II and III Transmission Panel Direct Cross Examination

Exhibit 2.

(CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit Number 2 was marked for identification.)

Q. Mr. Roberts, please let me know when you've had a chance to review the document.

A. (Witness peruses document.)

Okay.

Q. Can you speak to transmission projects that -- or upgrades that stem from House Bill 951 compliance and how those might differ from transmission projects or upgrades that are needed for reliability purposes?

A. Yeah. So one of the -- we have an asset management program, and so replacing wood poles with steel poles. That could be an outage that you could potentially delay or reprioritize associated with if you needed to get this generation interconnected and thus you needed an outage to facility that associated upgrade by a certain date to ensure compliance with the law.

Q. Is there a percentage -- are you aware, off the top of your head, if there's a percentage of expected transmission investments in the Carbon Plan that are for reliability purposes versus that are for the carbon emissions reduction goals?

A. Right. So, you know, we conduct TPL-001 NERC standard analysis on an annual basis, and there are projects associated with that that are reliability projects. And they have to be implemented by a certain time or you're not in compliance with the NERC standards.

So those are reliability projects that you're gonna have to do by a certain date in order to ensure compliance with that NERC standard that's mandatory.

House Bill 951, you may have a generator interconnection network -- associated network upgrade and just, you know, happens that that network upgrade grade can be done earlier than what's showing up in a TPL-001 study. That's a reliability project. So the same project that accomplishes both, you just are doing the 951 project early to be able to interconnect the generation.

Q. And are the costs for both of those type of projects incorporated into the Carbon Plan estimated present value of revenue requirements and associated rate impacts?

A. Right. So for TPL-001, you know, we're most likely gonna be doing that project anyway. You know, aside for House Bill 951 compliance. Asset management, replacing wood poles with steel poles. There may be synergies there, but that's a resiliency need. So we're gonna be doing that as well.

It's basically looking at what's needed to comply with the law and what's needed to comply with NERC standards and what's needed to ensure reliable customer service.

Q. So for the projects that Duke was going to be doing anyway, like you just testified to, are those costs included or not included in the Carbon Plan?

A. Yeah. So the network upgrade cost proxies are network upgrades associated with generator interconnections. And those cost proxies are what were the baseline inputs for determining the overall network upgrade cost of the -- implementing the Carbon Plan. So it's associated with generator interconnection.

Q. And not reliability?

A. I mean, that's in the eye of the beholder. If I don't have firm deliverability of resources that are requesting firm deliverability, interim service, then I'm not going to be able to reliability serve customers. I'm not going to be able to reliably charge a battery, et cetera.

Q. Okay. Thank you. And last couple of questions here. The last exhibit as well, which is Duke's response to AGO Data Request 3-11.

MS. CRESS: And I'll request that this exhibit be marked and identified as CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit 3.

CHAIR MITCHELL: All right. The document will be marked as CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit Number 3.

(CIGFUR II and III Transmission Panel Direct Cross Examination Exhibit 3 was marked for identification.)

MS. CRESS: Thank you, Chair Mitchell.

Q. Please let me know when you are ready and have had a chance to review the document.

A. (Witness peruses document.)

Okay. And I'll just go on the record that I wasn't the one that responded to this data request.

Q. Yes. Thank you for that. And if I need to direct this question to Mr. Snider on rebuttal, I'm happy to do that, so just let me know.

If Duke was directed to attempt to quantify potential transmission cost savings associated with brownfield development at retiring coal sites, could it do so?

A. There are transmission studies that could be performed that look at -- I mean, it depends on the location of the replacement generation. If network upgrades are required that are modest associated with the generation being replaced sort of close to the existing site, then that's one story. If generation needs to be -- that generation replacement needs to be located at a pretty good distance -- and once again this is based on how -- where load centers are, et cetera, where other resources are, et cetera -- but the upgrades could be significant.

The purpose of generator replacement process at a brownfield site is that you are not gonna require network upgrades associated with replacing that generation.

Q. Thank you. Nothing further.

CHAIR MITCHELL: All right. At this point, let's take an afternoon break. We will be back on at 3:25. Let's go off the record, please.

(At this time, a recess was taken from

3:12 p.m. to 3:26 p.m.)

CHAIR MITCHELL: All right. Let's go back on the record, please. All right. Mr. Snowden, you're up.

MR. SNOWDEN: Thank you.

CROSS EXAMINATION BY MR. SNOWDEN:

Q. Good afternoon. Ms. Farver, Mr. Roberts. Ben Snowden with CPSA.

Mr. Roberts, I'd first like to start out by talking a little bit about the red zone transmission expansion project, or I guess we'll call -- is it RZEP, is that the way you prefer to refer to it?

A. (Sammy Roberts) That's correct. That will be fine.

Q. Okay. Thank you. So, Mr. Roberts, in your testimony, you discuss the supplemental studies that the Company performed to validate the need for the RZEP; is that right?

A. That's correct.

Q. Okay. And those studies are based on approximately 5,400 megawatts of generation in DEC and DEP together; is that right?

A. That's correct.

Q. And that aligns with the amount of solar that's required to get to 70 percent carbon reduction in portfolio P1, correct?

A. That's correct.

Q. Okay. So the reports that are attached to your testimony in Exhibits 3 and 4, we don't -- I'm not gonna get into any detail there. But would you agree that they say that the analysis shows the need for additional upgrades to reliably interconnect the 1,937 megawatts of added solar generation in DEC?

A. That's correct.

Q. Okay. And the analysis also shows the need for additional upgrades to reliably interconnect 3,527 megawatts of added solar generation in DEP; is that right?

A. That's correct.

Q. Okay. And those additional upgrades are the RZEP, right?

A. That's correct. So the supplemental studies validate what we've been seeing for several years now with respect to processing generator interconnection request, and these common upgrades keep showing up. And these common upgrades are a hurdle, tall hurdle. And it basically results in solar developers withdrawing their projects from the queue.

Q. Thank you, Mr. Roberts. And thank you also for mentioning common upgrades, because it probably is helpful to clarify.

Anytime a generating project or a solar generating project is interconnected to the transmission system, it's gonna require some upgrades at the point of interconnection, right?

A. Yes, that's correct. You're gonna have blind switches installed for isolation or you could possibly have to have a breaker station installed. So yes, those are associated with network upgrades.

Q. Okay. But a project may or may not require what I'll call thermal upgrades to Duke's system of the kind that you see in the RZEP; is that right?

A. That's correct. That's correct. But I would say that, you know, we're seeing more and more that -- projects that are desiring to interconnect in the red zone. There's reasons. You know, those reasons are primarily land lease rates, the land availability, lack of significant forestation, lack of population density, et cetera. And because of those reasons, it's fertile ground with respect to locating large solar facilities. Unfortunately, there's transmission constraints that are locking that up.

Q. Thank you. So setting aside those upgrades at the point interconnection that we just talked about, and understanding that the exact upgrades that would be required for a specific project depend on the size and the location of the project, would you agree that the red zone upgrades would be sufficient to accommodate at least 5,400 megawatts of generation sited in the red zones?

A. So the red zone projects will enable a significant amount of generation. And the entire 5,400, some of that was located outside the red zone, some of that, a large portion of that was located inside the red zone, because we indiscriminately chose the solar facilities to be studied by looking at the most recent history.

So it included transmission cluster study, solar facilities, and then you went back far enough in the serial queue to get the 5.4 gigawatts. 1.9 gigawatts in DEC and then the remainder 3.6 gigawatts in DEC -- or DEP, excuse me.

Q. Thank you. So those red zone upgrades were sufficient to facilitate the interconnection of that 5,400 megawatts that was used in the studies, right?

A. So there may be small upgrades needed. And like you said, it depends on megawatt size and location. In studying these projects, this portfolio of solar products, once again, it showed, for those wishing to site in the red zone, or the generator interconnection request for the red zone, it did show that a majority of the red zone projects were needed. I think it was 15 out of the original 18 were needed.

Q. Thank you. And that 5,400 megawatts that we've talked about, that is a lot more than Duke proposes to procure in the 2022 procurement; isn't that right?

A. Yeah, that's correct.

Q. Okay.

A. The target is 750, I believe.

Q. Okay. And it's also more than the total target procurement volume that Duke has requested over the full near-term execution plan, isn't it?

A. That's correct.

Q. Thank you. So, Mr. Roberts, I want to turn to page 30 -- pages 37 and 38 of your testimony. It's really starting at the very top of 38. But here the Public Staff has identified concerns about the potential of -- and I'm reading here from -- excuse me, top of 38 where it says, "The potential risk of building transmission only to have it replaced by future upgrades in the first 10 to 15 years of the original asset's 40-to-60-year asset life"; do you see that?

A. Yes, I do.

Q. Okay. And what was your response to that risk identified by the Public Staff?

A. Yeah. So as written in my testimony, where, you know, it makes sense, and using standard materials that we have -- and I refer to an example of the Cape Fear West End 230 line -- instead of just upgrading to get to that level associated with the study results, we're using bundled 1,590 versus the current single 1,272 cmil wire. And that facilitates increasing the rating up to 1,195, which I believe is 121 percent increase in the rating.

So with that said, there will be sufficient space to accommodate more solar interconnections than what were studied.

Q. Thank you. So just in layman's terms, you design the upgrade so they're big enough so they create some headroom beyond what they were originally spec'd for; is that accurate?

A. That's correct. Where it makes sense from the transmission planner's perspective.

Q. Thank you. Can you quantify or maybe just estimate how much headroom for additional generation RZEP would create?

A. Other than the 5.4 gigawatts of supplemental studies, I don't have that number.

Q. Okay. Well, understood. I mean, is there a number that even directionally could suggest? Is it 10 percent headroom or 30 percent? I mean, any -- and again, I understand that it really depends on what actually interconnects, but is there any way to, kind of, ballpark that headroom?

A. Yeah. I mean, the only way I would be able to give you an answer is to conduct a study and get some input from all the solar developers on location and size projected, or take some information from the 2022 DISIS and model that and see what the results are.

Q. Okay. Thank you. So, Mr. Roberts, you would agree, wouldn't you, that Duke currently projects that the red zone upgrades are all scheduled to be completed by mid-2027?

A. That's correct.

Q. Okay. And, in fact, all of but one of them are scheduled to be completed by the end of 2026, aren't they?

A. That's correct.

Q. Okay. So would you agree, then, that by mid-2027 Duke expects -- contingent upon the agreement of the transmission planning collaborative, Duke expects to have completed the major transmission upgrades that would be required to support somewhere more than 5,400 megawatts of solar projects in the red zone?

A. Once again, it would be dependent on location and size. The supplemental studies are indicative of being able to connect by 5.4 gigawatts. And once again, there are some of those projects that were outside the red zone.

Q. Thank you. So thinking about -- with the understanding that Duke has got finite interconnection resources, would constructing the red zone upgrades on the schedule that's proposed, along with any other required reliability upgrades, would that preclude construction of any other major transmission upgrades through 2027?

A. Yeah. So -- and I speak to this in my rebuttal testimony, but I'll bring it forward to answer your question. So, I mean, we have an extensive job with respect to outage coordination to ensure we maintain reliability for our customers. Aside for -- just looking at the outages for interconnection facilities like you referred to, I've got to replace line switches, that requires an outage; I've got to do relay work, that requires an outage; if I have to do a network upgrade, that's gonna require an outage possibly over multiple outage seasons. I've also got outages for maintenance. I've got outages for asset management projects. And then there's storms. So you may have to do restoration associated with unplanned outages associated with those storms.

So there's -- there's a lot to coordinate with respect to outages. And we can't just turn off the power system and say we're gonna do network upgrades associated with generator interconnection for three months. We have to coordinate all that such that we can handle worst-case contingencies and we can ensure reliable service to our customers.

Q. So what I'm hearing your answer to be is maybe, maybe not?

MS. KELLS: Madam Chair, could Counsel repeat the question?

MR. SNOWDEN: Well, I mean, the question

was -- the question was whether constructing the red zone upgrades and any reliability upgrades would preclude construction of any other transmission upgrades through 2027. I believe that Mr. Roberts identified a bunch of factors that could affect whether the answer was yes or no.

Q. And so I guess I'm paraphrasing you to say -- as I understand your answer is maybe, it depends on a lot of factors, I don't really know?

A. Yeah. So I went through an example in one of the stakeholder meetings, and I'm pretty confident it was associated with, like, implementing what we know as the region upgrades. And if you take two of those 230 lines out during the same time, and you have this contingency of 500 kV line, you will most likely overload the underlying 115 kV line. I gave that example in the stakeholder meeting. So that's an example of you really can't take those two 230 lines that are in parallel out at the same time.

Q. Thank you, Mr. Roberts. And honestly, I was really just asking about the Companies' resources rather than the specific calendar, but I'll move on.

So in addition to the study that was filed in your testimony, what information did Duke rely on to identify the need for the red zone upgrades? And I know it's in your testimony, if you could just say it briefly.

A. So it's -- yeah, it's been an evolution. Starting with our first map in 2018, we showed the red zone congested area with respect to, you know, if you request interconnection in this red zone, you're probably gonna get faced with, you know, some decent network upgrades required. And this was during the serial queue process. And so it was basically stating, you know, stay away from the red zone if you want the -- if you don't want the network upgrade cost to be up.

The concern going forward is that other areas are gonna become red zones, and we're quickly running out of any space. And I think I have a map -- Figure 3 -- that shows the high solar viability areas associated with the red zone projects being overlaid with that map. And those darker green areas are where you don't have significant forestation, you don't have population density, you don't have state parks, federal parks, et cetera.

And you can see that these red zone projects enable utilizing that area for solar generation. It's

Figure 3 on page 36. Sorry.

Q. Thank you, Mr. Roberts. So you'd agree, though, that the red zone upgrades are unlikely to be the last set of upgrades that are necessary to comply with HB 951, wouldn't you?

A. That's correct.

Q. So when it's time to identify the next set of upgrades, it seems fair to say that you will not have quite the same track record or amount of information about interconnection requests that you had to identify the red zone upgrades; is that fair to say?

A. That's correct.

Q. So I guess my question is, how -- if you know, how is the Company planning to go about identifying that next set of least regrets upgrades necessary to achieve compliance?

A. Yeah. So aside for generator interconnection requests, DISIS studies, we'll also need to look at some scenario-based -- some scenarios, transmission planning scenarios. And, you know, tend to try to look for the transmission upgrades that will be needed holistically to provide synergies, multiple different types of resources being connected. And also, you know, that will be least cost with respect to connecting a certain type of resource, like solar.

Q. Thank you. In that kind of scenario-based analysis, is that something that could be done within the context of a TPC?

A. Yes. I believe that could be been done in the NCTPC process.

Q. Okay. Thank you. Mr. Roberts, you testify on page 18 of your testimony that the current interconnection process requires an approximately two-and-a-quarter-year period from the time the interconnection request is made to the time an interconnection agreement is signed.

That's on line 3 of page 18; do you see that?

A. Yes.

Q. Okay. When do you anticipate -- or when does the Company anticipate entering into interconnection agreements for projects that are in the DISIS process now?

A. Yes. So for the 2022 DISIS, where the enrollment window started beginning of this year, you're looking at signing IAs in the first quarter of '24.

Q. Okay. And you mentioned that the enrollment window started at the beginning of the year, but that was a six-month enrollment window; is that right?

A. That's correct.

Q. Okay. So it ended at the end of June 2022; is that right?

A. That's correct.

Q. Okay. So from the time that projects that -- from the time that projects were required to bid into the RFP and the time that enrollment window closed, it's really closer to a year and a half to -- from interconnection request to interconnection agreement; would you agree?

A. If the interconnection request was made toward the end of the enrollment window, yes.

Q. Okay. Thank you. And, Mr. Roberts, for a project that does not require thermal upgrades, that might only require the kind of upgrades that the point of interconnection as we discussed before, how long would you anticipate it would take from signing of the IA to completion of construction?

A. Yeah. So for interconnection facilities alone, once again, it's -- you got to look at the outage coordination to facilitate that, et cetera. So with the interconnection facilities, depending on how involved, year to two.

Q. Okay. So one to two years. So for those kinds of -- I'm sort of adding this together.

For projects that don't require significant thermal upgrades, you'd be looking at two-and-a-half to three-and-a-half years for the total time from interconnection request to completion; does that sound right?

A. That sounds about right.

Q. Okay. Thank you.

Ms. Farver, I've got a couple questions for you, mostly going to DISIS and the current RFP.

So, Ms. Farver, you describe the current status of DISIS in the market response to the 2022 solar RFP in your testimony, don't you?

A. (Maura Farver) That's correct.

Q. Okay. And on page 36 of your testimony, you say that of the more than 5,000 megawatts proposals received, over 70 percent of the megawatts are located in known red zone areas.

Do you see that?

A. That's correct. That's where there's a correction of the testimony that of the approximately 4,900 megawatts of proposals received.

Q. Thank you for that correction. Of the more than 4,900 megawatts. Thank you.

So my math is not as good on the fly as this, but around -- does that mean around 3,500 megawatts of proposals were received in the red zone?

A. Approximately.

Q. Okay. And approximately 1,500 megawatts of proposals outside the red zone?

A. Yes, roughly.

Q. Okay. Thank you. So of those projects outside the red zone, has Duke identified any proposals that are located in other areas of Duke's grid that are constrained?

A. This is information that will revealed during the DISIS cluster study process. And so when we have phase 1 and eventually phase 2 reports, we'll know if other constraints come up for those projects that are outside of the red zone.

Q. Okay. Well, thank you for that. And I understand that that will be provided on an official basis to interconnection customers at that time.

Do you know now, sitting here, whether Duke has identified any proposals that are in constrained areas of the grid?

A. Outside of those red zone areas, I do not know.

Q. Okay. Has Duke been able to ascertain, even on a preliminary basis, whether any -- any non-red zone projects could be interconnected without construction of thermal upgrades out of those projects that have gone into DISIS?

A. I don't believe we have that information yet.

Q. Okay. So it's not -- it's your understanding that Duke has not tried to, sort of, ascertain, even, sort of, informally or on a preliminary basis, how many projects bid into DISIS are located in unconstrained areas of the grid?

A. I don't believe so. The interconnection review process doesn't consider whether they're participating in an RFP when they're doing their studies.

Q. Okay. Thank you. Do you know, in the context of the RFP, whether Duke or the independent evaluator has made any sort of preliminary assessment of how many projects are in constrained areas and how many aren't?

A. Aside from the red zone constraints, no.

Q. Okay. I assume that Duke has taken a look at the bids that have been received?

A. Generally.
Q. Generally?
A. Yes.
Q. Okay. So when you say "generally," does that mean on an aggregate basis? Or what do you mean when you say "generally"?
A. I have knowledge of some of the details but not all.
Q. Okay. Just very briefly, Ms. Farver, could you explain what the solar reference cost is, or solar reference price?
A. Yes. The solar reference price -- I'm probably paraphrasing Mr. Kalemba's testimony -- was the price that was assumed in the modeling for the solar that would be selected in 2026.
Q. Okay. Thank you. And that solar reference price is the basis of the volume adjustment mechanism that is approved for the RFP; is that right?
A. That's correct. That's the reference that we're using.
Q. Thank you. And the current RFP provides for bidders to be able to refresh their pricing downward come April 2023; is that right?
A. That's right. There is an opportunity for

proposals that are invited to step 2 to adjust their bid price in the downward direction.

Q. Thank you. But only proposals that are advanced to step 2 would have that opportunity; is that right?

A. That's correct.

Q. Okay. Thank you. Now, I want to be clear I'm not asking you to discuss any confidential information, and I understand that there will be a bid refresh in April.

Can you say what the average price for proposals in the 2022 RFP that had been received by Duke is?

A. That's confidential to the RFP.

Q. Okay. Can you say whether it is above or below the solar reference price?

A. I think that's also confidential to the RFP.

Q. Okay. Ms. Farver, you are familiar with Duke's proposal to procure remaining CPRE megawatts using bids in the 2022 RFP, aren't you?

A. Yes, I am.

Q. Okay. And for -- as it's proposed by Duke, for bids to be selected to fill the CPRE gap, they would need to be below avoided cost; is that right?

A. That is our proposal.

Q. Okay. And would that avoided cost calculation include network upgrade costs?

A. That was how it was used for the earlier tranches of CPRE, and so presumably that would be the same for this last consideration of CPRE.

Q. Okay. Does the Company have a sense of how many megawatts of projects or how many projects that bid into the 2022 RFP are below avoided costs?

A. That is confidential to the RFP.

Q. Okay. Do you think that it would be helpful for the Commission to have that information in considering Duke's CPRE proposal?

A. That is difficult, because the prices that we have are still available to bid in the downward direction, and so what we know right now is likely going to change. And so, obviously, there have been changes to law with the IRA being passed, and we anticipate that could provide an opportunity for more bids to be comfortable with refreshing downward come April.

So I don't know that the prices that we have right now are going to be truly indicative of how many offers are below that avoided cost threshold. We also don't have the network upgrade cost estimates at this point in time, and so that's another key piece of information to determine if they are below that threshold or the reference cost threshold.

Q. Okay. Understood. Do you think it would be helpful for the Commission to have in its hands any aggregate information about the bids that were received for the 2022 RFP in deciding how to proceed more generally in this docket?

A. I don't know that the aggregate information is going to be that helpful, given the qualities that I just described of not having the upgrade estimates at this point in time and still having an opportunity for refreshing the downward direction. So I don't know how helpful it would be.

Q. So, Ms. Farver, as you said, the bids were submitted to the RFP prior to the passage of the Inflation Reduction Act, right?

A. That's correct.

Q. Okay. And so there will be this opportunity for bidders to refresh their pricing in April to reflect the IRA, right?

A. That's correct.

Q. Okay. Presumably that will -- that can only

drive prices in one direction, and that's down, right?
A. Correct.
Q. Okay. On the other hand, do you recall that the -- per the Commission's instructions, in an order issued in the RFP docket, the red zone projects are not in the baseline for DISIS-1, right?
A. That is correct.
Q. Okay. And my recollection is that that was based on a finding by the Commission that, at that time, no party had presented competent evidence that the red zone projects were necessary to achieve the Carbon Plan requirements; is that right?
A. Subject to check, but yes, that's my interpretation.
Q. Thank you. And it's Duke's view that it has presented that kind of competent evidence now, right?
A. That is correct.
Q. Okay. So under the current interconnection process, if red zone projects are selected in the RFP, they're gonna trigger those red zone upgrades, right?
A. So those projects that are in DISIS will collectively be studied and will be recognized for whatever upgrades are necessary for them to interconnect. Whether or not those upgrades are in the

red zone, I don't think --

Q. I tell you what --

A. I'm not sure if I'm answering --

Q. Maybe this is a question for Mr. Roberts.

So, Mr. Roberts, if a -- is it fair to assume that if a project that bid into the RFP was in the red zone and it was selected to proceed to step 2 and it was going to be -- its interconnection was gonna be analyzed, it's very likely that those red zone upgrades, or some substantial subset of them, would be triggered by those projects, right?

A. (Sammy Roberts) Depending on location and size, yes.

Q. Okay. And as -- under Duke's interconnection process as it currently exists, the full cost of the red zone projects would be allocated to the DISIS projects that triggered those upgrades, right?

A. So I may ask Ms. Farver to answer this, but my understanding is the 2022 procurement that the -- this Commission approved, and what has been presented on how we will conduct the analysis of those bids, yes, that cost of that upgrade needs to be considered.

Q. Okay. Understood that we may not have, sort of, full information, but that's the way it, sort of, looks right now under the current interconnection process, right?

A. That's correct.

Q. Okay. And the full cost of those upgrades would be assigned -- would be allocated to those projects, even though those projects would create headroom for a total of something like 5,400 megawatts of projects, maybe more than that; is that right?

A. (Maura Farver) I think, depending on the timing of the NCTPC approval of these red zone upgrades, that would inform whether their phase 2 study lists those upgrades as a contingent facility or whether the price is assigned to the generator.

However, for the RFP evaluation purposes, it's our understanding that the Commission's order has indicated that those costs, or the portion of that cost that would be assigned to the generator, should still be considered in the evaluation and ranking of the projects in step 2.

Q. So if the costs of the red zone upgrades are allocated to projects that are selected in the 2022 RFP, those costs could potentially drive the sort of total cost of the procurement up a lot, right, or the apparent cost, wouldn't they?

A. Can you repeat that?
Q. Sure. I mean, just assuming that the projects in the red zone were selected and the full cost of the red zone upgrades was allocated to those projects, that could potentially drive the total cost of the procurement, or at least the apparent cost of the procurement, up significantly because the full cost of those upgrades would all be assigned to the 2022 procurement, right?
A. If you mean by apparent cost for evaluation purposes, taking the portion of the allocation of that generator, then yes.
Q. Okay. Thank you. Would you agree, though, that the more megawatts of projects in the red zone that would be selected in the procurement, the more those costs would -- of those upgrades would be spread around?
A. Certainly. The cost of network upgrades are allocated across those generators that are causing the upgrade.
Q. And so a larger number of projects in the red zone would dilute that, sort of, distorting effect on the cost of allocation; is that right?
A. That's true.

Q. Thank you. Mr. Roberts, going back to you for just a couple of minutes.

You're aware that CPSA has recommended that an independent technical advisory committee be established to study the achievability of higher solar interconnection rates in Duke's territory and advise the Commission on measures that could be taken to expedite interconnection?

A. Yes.

Q. Okay. I -- from reading your -- and this is around page 42 of your testimony. I got to say, from reading your testimony, I can't tell, does the Company oppose that? And I don't need your reasoning, but I just -- I just am trying to understand what the Companies' position on an independent technical advisory committee would be.

A. Yes. So, I mean, we feel that the internal process improvements that we have actually presented in the stakeholder meeting, discussed in the stakeholder meeting, as well as discussed with some solar developer parties, we feel like those process improvements will save time on the end-to-end interconnection process with respect to, you know, submitting your request to getting an IA, if that's what you're referring to.

Q. Okay. Thank you. You say in your testimony that the Companies continue to work to identify additional opportunities to improve efficiencies.
Is that what you're referring to?
A. That's correct.
Q. Okay. Thank you. And you say that the Companies initiated process improvement workshops during first quarter of 2022; is that right?
A. That's correct.
Q. Okay. And there were two workshops held at that time?
A. Subject to check, yes.
Q. Okay. How many workshops have been held since then?
A. I don't know. To be honest, I don't know the answer to that.
Q. Okay. So you haven't been involved in any process improvement workshops since the first quarter of 2022?
A. So I was involved in the first one, and I have not been involved in the others since then.
Q. Okay. So as Duke's witness testifying on the subject, you don't know if any further process improvement workshops have been held since the first

quarter of this year?
A. I do not.
Q. Okay. Do you know what the Company has done since those workshops were held to implement and process improvements?
A. Yes. A lot of actions have been signed to -- assigned to different groups to basically execute on the efficiency gains identified.
Q. Okay. Could you tell me specifically what that means?
A. Sure. For example, with the interconnection facilities -- well, that's after the process. Let me make sure I go back to the process and identify one specifically for you.
(Witness peruses document.)
Okay. Yeah. Basically with respect to, you know, study times, potentially shortening those study times, and that's -- that would be in agreement with the solar developers, because there's a certain timeline associated with the DISIS process.
Q. Mr. Roberts, I understand -- I'm sorry, I didn't want to interrupt you. I understand that shortening study times is a goal that we can all agree on. But I guess what I'm asking for is whether

anything's actually been done.

A. Yeah. I mean, there are people actually looking at what it would take to implement efficiencies identified.

Q. Okay. Now, other stakeholders were not invited to those process improvement workshops, were they?

A. Not the workshops, that I'm aware of, no.

Q. Okay. And would you be surprised to hear that the folks at the solar development companies have not heard anything from Duke about being engaged in a process improvement initiative on interconnection?

A. I would be very surprised about that, because, you know, I know of one meeting held with a few solar developers where we specifically discussed the -- looking for improvements and efficiencies with the interconnection process.

Q. Was that a meeting where you -- I think we may have been on the -- I'm not sure if I refer -- if I know what you're referring to.

Was that a meeting where Duke summarized its activities with regard to the process improvement workshops to solar developers and told them what was going on in that department?

A. I did not attend that meeting, but the slide deck that I recall had two to four slides associated with that process improvement.

Q. Thank you. Well, Mr. Roberts, would the Company be willing to engage solar developers or other stakeholders in, sort of, more fulsome discussions of process improvements that could be made to speed up interconnection times?

A. Yeah. I mean, I would recommend, you know, let us basically develop the current state of our process improvement event and present that to stakeholders and get feedback from that.

Q. Okay. Mr. Roberts, Ms. Farver, those are all the questions I have. Thank you very much.

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

UNIDENTIFIED FEMALE: Mr. Quinn, counsel for NC WARN, would like to waive his cross examination of this panel.

CHAIR MITCHELL: Okay. Thank you for letting me know. Yes, SACE, you're up.

MR. JIMENEZ: Thank you.

CROSS EXAMINATION BY MR. JIMENEZ:

Q. Hello, good afternoon. Nick Jimenez at the

Southern Environmental Law Center on behalf of Southern Alliance for Clean Energy, Sierra Club, and the Natural Resources Defense Council, referred to collectively as SACE, et al.

So I'd like to start with the red zone where we've been spending a bit of time. And I apologize if I cover any ground that has already been tread. Please help me keep that brief if I haven't been able to excise it from what I was already planning.

So Duke's proposed Carbon Plan, regardless of portfolio, depends on the red zone transmission expansion plan or RZEP projects, right?

A. (Sammy Roberts) Yeah. I mean, I would even go -- you could even go one step back and, you know, the 2020 IRPs had significant solar in those portfolios. And even those would require these red zone projects to implement that amount of solar.

Q. Thank you. Would it be safe to say that, in Duke's opinion, it will be impossible to achieve the 2030 carbon reduction requirement without those projects?

A. Yes. I mean, it would be extremely challenging to implement that amount of solar without the red zone projects.

Q. Thank you. And it will be impossible to reach the 2050 carbon reduction requirement without additional transmission upgrades beyond the red zone upgrades, right?

A. That's correct. I mean, we will need a -- will we have to have an iterative process looking at proactive transmission in order to execute the Carbon Plan.

Q. Thank you. So -- oh, and I forgot to give this disclaimer, if I direct this to the wrong person, please just correct me. I think most of these are for Mr. Roberts but -- okay.

Your testimony identified areas of high solar viability, or I think you referred to it recently as fertile ground, right?

A. That's correct.

Q. And those areas are actually mapped. I think it's figure 3 on page 36 of your testimony?

A. That's correct.

Q. Okay. And those are high viability for reasons other than transmission capacity, right, otherwise we wouldn't be talking about the red zone upgrades?

A. That's correct.

Q. And Ms. Farver testified that information about the red zone constraints hasn't seemed to drive project -- yeah, project development to other areas in any significant way, I think were the words; is that right?
A. (Maura Farver) That's correct.
Q. Thank you. And Mr. Roberts similarly testify that had solar developers keep submitting and then withdrawing in the red zone, right?
A. (Sammy Roberts) That's correct.
Q. Thank you. And in the supplemental studies, Duke recognized that the red zone upgrades, themselves, might incentivize additional requests; isn't that right?
A. That's correct.
Q. So isn't it -- oh, and in response to Mr. Snowden recently, I believe it was Mr. Roberts testified that you can't identify whether or how much headroom those projects will provide; right?
A. I think the response was that, without studying and looking at scenarios, you can't definitively say, you know, that you can connect another 2,000 megawatts of solar in the red zone area over and above the 5.4 gigawatts that were analyzed.

Which is actually, -you know, in the red zone, once again, it's gonna be less than the 5.4 gigawatts, because some of those projects were outside the red zone.

Q. Okay. Is it fair to say that the red zone projects -- I think of them collectively, individually if you like -- are more likely to be undersized than underutilized?

A. Well, based on using transmission planning knowledge of running system impact study after system impact study, that's where the experience can be applied with respect to, you know, if you know -- if you size it just to cover the amount of megawatts, you know, within five years, et cetera, that you're gonna need an upgrade again, based on the magnitude of solar that needs to be interconnected.

Q. Okay. Thank you. Not shifting too many gears, I'd like to ask a little bit about advanced transmission technologies and grid enhancing technologies.

Is it okay with you if I refer to those both as advanced transmission technologies?

A. Sure.

Q. Okay. Isn't it true that advanced

transmission technologies, like advanced conductors and dynamic line ratings, can enable greater transmission capacity on existing assets and corridors?

A. Yes. But you need to look at the cost and the associated benefit.

Q. Sure. Thank you. And all else equal, using existing assets and corridors saves money over greenfield development, right?

A. Yes.

Q. Thank you. And isn't it possible that the savings from leveraging existing assets would more than offset any additional upfront cost of advanced transmission technologies over conventional bills?

A. Could you repeat your question? I heard two things in that question.

Q. Sure. Isn't it possible that those savings from leveraging existing assets, using advanced transmission technologies, would more than offset any additional upfront cost that those advanced transmission technologies might have over a conventional bill?

A. I can't say yes or no to that, I mean, without a cost analysis.

Q. Would you agree that advanced transmission technologies can benefit ratepayers by increasing transmission capacity at low cost?

A. And when you're talking about advanced transmission, you're talking about different types of high -- high-strength conductors, different configurations of conductors?

Q. That would -- I think that is advanced conductors. So certainly the composite core, you know, high-capacity conductors would be one of the suite of technologies. I believe in your testimony, I think it's page 41, you gave a list of various -- and I'm sorry if that's wrong, that's completely from memory -- various advanced transmission technologies. Page 44, according to my notes.

A. Yeah, yeah. So in there I talk about how we have implemented some high-technology conductors system, and then we've had some issues, concerns that we're addressing associated with those.

Q. Certainly. But just -- so putting those concerns to the side, assuming that advanced transmission technologies function as they're supposed to, it can benefit ratepayers by increasing transmission capacity at low cost; would you agree?

A. I don't know about the low cost piece of that, but, I mean, it depends. Every application is different, right? And if you've got, you know, standard conductor versus, you know, some high-capacity different technology, emerging technology conductor, I mean, you got to now keep that in the warehouse versus your standard conductor, right?

Q. Understood.

A. So once again, you would need a cost analysis to look at the cost benefit associated with the application of it.

Q. Thank you. You testified that the Commission does not need to require Duke to consider advanced transmission technologies because Duke has and will continue to investigate their potential benefits, right?

A. That's correct. I mean, we've applied things like remedial action schemes and all those swapovers and line reactors, switchable line reactors, bay-shifting transformers that -- I mean, those are more in the area of flow control devices. But like I said, we've also looked at different advanced technology conductors as well.

Q. But Duke's consideration of advanced transmission technologies isn't discussed or analyzed in the Carbon Plan filing, is it?

A. No. I believe it is not addressed in the Carbon Plan filing, itself.

Q. Thank you. Okay. Shifting again to proactive transmission planning. So we've had a little discussion of the NCTPC.

Duke believes that transmission planning for North Carolina must move from this reactive process driven by generator interconnection requests to a proactive forward-looking process anticipating transmission that will be needed in the future, right?

A. That's correct. Looking at the pace at which we're gonna need to interconnect new resources to make this transition and comply with the law, proactive transmission will definitely be needed.

Q. Thank you. And Duke will work through the NCTPC's local transmission planning process to resolve transmission issues related to the Carbon Plan?

A. Yes.

Q. And -- scratch that.

And the NCTPC is run by an independent administrator, right?

A. That's correct. There's an independent entity that administrates the process.

Q. Thank you. And you testified that Duke hopes to be able to incorporate the RZEP into the local transmission plan by midyear 2022, right?

A. So the original goal was to incorporate the red zone expansion plan projects into the midyear update, but in the 2022 solar procurement order, the Commission said that -- directed us not to include those red zone projects into the 2022 DISIS, and required further evidence that these were needed and gonna be used and useful.

And in addition, we received feedback from our June 27th TAG stakeholder meeting on these red zone projects, and based on that feedback, we agreed to not move forward with including the red zone projects in the midyear update.

Q. Okay. But that's the -- I'm sorry, which midyear update are you referring to?

A. So we had a -- there's always a TAG meeting to go over the midyear update report in the NCTPC. And so in that meeting, we also introduced the red -- including the red zone projects in that midyear update. And based on the TAG stakeholder feedback, in addition to the Commission's order that said -- directed Duke not to include the red zone projects in the 2022 DISIS, we issued a subsequent communication that we're not including the red zone projects into the midyear update.

Q. Okay. When you say "we issued," are you referring to Duke?

A. NCTPC.

Q. NCTPC. Thank you. So I'm sorry, I'm still not completely clear.

Was that the 2021 -- something titled the 2021 midyear update, or 2022?

A. No. So the 2021 midyear update is actually an update to the 2021 annual local transmission plan that's approved at the end of the year. So let me provide a timeline for you. So in the December time frame, the 2021 annual local transmission plan, that NCTPC conducts one every year, is approved, and the final report is usually posted in January.

There can be updates to that information that was included in that report as well as new projects, updated cost on projects, et cetera. And that information is presented in the 2021 report midyear update that occurs in 2022.

Q. Okay. Thank you. That's what I was trying to get. So I think you just said this, but just to clarify.

The NCTPC, for the reasons you gave, declined to consider the RZEP for the 2021 midyear update?

A. That's correct.

Q. Okay. Thank you. So the Commission can't be sure that the RZEP will be included in the local transmission plan by midyear 2022, can it?

A. So that's correct. So the current process, following the NCTPC process, we can present to TAG, which the Transmission Advisory Group and stakeholder group, which went into the addition of the red zone expansion plan projects for inclusion in the 2022 local transmission plan. And what we're asking for in this proceeding is acknowledgement from the Commission that the red zone projects are needed to execute the Carbon Plan.

Q. Okay. Thank you. Yeah.

So a few minutes ago, Ms. Farver testified, and I believe Mr. Kalemba testified roughly the same on the 13th, that there were approximately 1,500 megawatts in the 2022 RFP outside of the red zone; is that right?

A. (Maura Farver) Approximately.

Q. Thank you. Oh, and Mr. Kalemba -- Ms. Farver, were you in the room or did you review his

testimony?
A. I think I caught it. I'm not positive I caught all of it.
Q. If I represent to you that, on the 13th, he testified that those 1,500 megawatts are in areas that are not currently constrained but constraints might show up in the future --
A. That sounds right.
Q. -- would you agree? Okay. Thank you.
So would it be fair to say that the red zones could expand over time?
A. Or change, yeah.
Q. Okay. Thank you. And Duke agrees that the RZEP will not be enough for later stages of the Carbon Plan?
A. That's correct. There will be more resources needed.
Q. And you testified -- I'm sorry, I'm not sure if this was Ms. Farver or Mr. Roberts -- that additional upgrades, besides the RZEP, will even be necessary to get to 2030; isn't that right?
A. (Sammy Roberts) Yes.
Q. Thank you. And Duke's planning to submit a -- you testified Duke's -- sorry, I know this is in

Appendix P.

Duke is planning to submit a comprehensive 2022 public policy request study of long-range transmission needs for the Carbon Plan, right?

A. So there -- there is a 2022 public policy request that has -- was submitted to the NCTPC, and there'll be an associated response to that public policy request.

In 2023, a new public policy request will probably be submitted to -- and it'll be based on the Carbon Plan approved in this proceeding, or the near-term actions and Carbon Plan.

Q. I see. Thank you for clarifying that.

So with respect to that new submission, the Commission can't be sure that the NCTPC will grant the request, can it?

A. No. I mean, it -- like I said, the process, as defined in the OATT, is that the OSC has to -- well, you had to present the long-range transmission -- or the local transmission plan to the TAG stakeholder group, receive feedback, and appropriately address that feedback. And then in December, if the red zone projects are in the local transmission plan, the OSC, the Oversight Steering Committee, will vote on approval of that plan.

Q. Thank you. And the Commission also can't be sure that the NCTPC will approve all of the transmission upgrades that are necessary for this and future Carbon Plans, can it?

A. That's correct.

Q. Thank you.

A. I mean, in a worst-case scenario, which, you know, the associated delays may not be tolerable from compliance perspective. But in a worst-case scenario, the DISIS in associated interconnection, resulting interconnection agreements would drive the network upgrades for interconnecting facilities.

Q. Thank you for explaining that.

So given the uncertainty about what the NCTPC will do, wouldn't it be safer to plan transmission and resources simultaneously, assuming that's possible?

A. That's discussed in my testimony about making sure that resource planning and transmission planning are aligned and integrated.

Q. Correct me if I'm wrong, I don't recall your testimony proposing that they be planned simultaneously, does it?

A. It just says the transmission planning and resource planning need to be aligned and integrated, which to me would be -- mean they're, you know, somewhat interlocked, associated with ensuring the transmission is gonna be there in time to facilitate interconnecting the resource that you're counting on in the Carbon Plan.

Q. Okay. Couldn't the Commission condition its order on the final Carbon Plan on Duke having a planning process that plans transmission and other resources simultaneously?

MS. KELLS: Madam Chair, I object to this speculative question.

CHAIR MITCHELL: You want -- would you like to respond, Mr. Jimenez, to the objection?

MR. JIMENEZ: I think the Commission can take the response for what it's worth. The witness is an expert on transmission planning and the processes around it.

CHAIR MITCHELL: All right. I'm gonna overrule the objection, allow the question. Do your best to answer it.

THE WITNESS: Yeah. So --

MR. JIMENEZ: Thank you.

THE WITNESS: -- so the transmission

process, once again, as defined in our OATT, is a FERC-approved process, and we have to follow that process. Just like the large generator interconnection procedure in our OATT, that's a FERC-approved process. The state interconnection procedure is a state-approved process.

Q. So you testified that -- and I'm shifting gears to a different topic here. Most off-system resources that Duke would purchase are non-dispatchable and therefore wouldn't help with renewable integration, right?

A. That's one of the concerns, yes.

Q. And we heard from the operations panel earlier today that geographic smoothing occurs at least to an extent, right? If I use that term, do you know what I mean?

A. You can refresh my memory.

Q. Sure. So I believe the question said geographic smoothing is essentially that the output of variable renewable resources becomes less variable in the aggregate as the region that they're in expands.

A. So yes, I remember Mr. Peeler responding to that. So, I mean, each -- each BA has to comply with BAL standards, NERC standards, and so the intermittency associated with the solar resource, for example, or other wind resource has to be balanced within that balancing authority area.

And so once again, through a merger, you would increase the size to 35-, 36,000 megawatts or more. I don't know the exact number. And through sharing operating reserves within that merged utility, you would be able to more cost-effectively manage the intermittency.

Q. Okay. So thank you. Am I understanding that you -- that you do think geographic smoothing would occur through the merger?

A. So, you know, we would have to -- through the House Bill 951, my understanding is we would have ownership of the resource, even off system, and so we would have to bring that into our system via, like, a pseudo-tie. And so our system would have to balance around whatever that pseudo-tie amount is.

If you're -- if you're talking about having diversity of resources, it depends on size for solar. I mean, if I have a -- if you're counting on diversity of solar to smooth out the intermittency, if I have 300-, 400-megawatt solar facility, partly cloudy days can cause a lot of intermittency associated with that.

Q. Okay. So I'm not sure if can take away a yes or a no from that.

Do you think geographic smoothing wouldn't happen?

MS. KELLS: Objection. The question's been asked and answered twice.

MR. JIMENEZ: I can move on.

CHAIR MITCHELL: Okay. I'm gonna sustain the objection.

Q. Wouldn't that same phenomenon apply to variable resources in other regions?

A. So you're saying if you had an extremely large solar facility that -- what phenomenon are you referring to?

Q. The geographic smoothing phenomenon with all the caveats that you gave.

A. Yeah. I mean, as a balancing authority, they're gonna have to comply with the BAL standards, so they're gonna have to have sufficient reserves to manage any kind of variable energy output.

Q. Okay. So hasn't Duke imported at least 1.2 gigawatts in the past five years?

MS. KELLS: Objection. Is counsel pointing to testimony or something to --

MR. JIMENEZ: We heard that from -- testimony from Mr. Snider in response to Mr. Quinn on the 14th at 5 minutes and 50 seconds.

THE WITNESS: I'm not sure I caught that piece of the testimony.

CHAIR MITCHELL: All right. I'm gonna -- I'll sustain her objection. Can you restate the question or give him context for the question so that he can answer it?

MR. JIMENEZ: Okay.

Q. So I want to ask a little bit about past transfers just to get a sense of -- well, I don't know how much preface I can give. In prior testimony, I'll represent to you that we heard -- if you weren't here, we heard from Mr. Snider in response to Mr. Quinn for NC WARN, et al., that, on September 14th, that Duke has imported 1.2 gigawatts -- I believe it was actually in the past two years.

Does that sound right to you?

A. I mean, I know we currently have 1.6 gigawatts of off-system purchases.

Q. Okay. Thanks. And on the 15th, we heard Mr. Snider, in response to Ms. Luhr, testify that Duke plans for over 2 gigawatts of neighbor assistance.

Does that sound right to you?
A. That's correct. That was from our 2020 IRP resource adequacy study and the non-firm assistance from neighbors around 2 gigawatts.
Q. Thank you. Didn't Duke's decision to make those imports take into account any border charges?
A. No. I mean, that's -- that study did not consider any border rate or border charges for non-firm assistance from neighbors.
Q. Okay. Well, if we move from the study to the actual imports, the 1.2 gigawatts, wouldn't that decision take into account any border charges?
A. So the 1.6 gigawatts, if there is any point-to-point rate transmission rate, we would have to pay that.
Q. Thank you. And can I assume that those imports were economical?
A. They're long-term purchases, so yes, I mean, they were economical based on the need for winter-peaking capacity.
Q. Thank you. Okay. Shifting gears one more time to coal retirements and related things.
So you testified that in order to retire coal plants, Duke will have to ensure that any transmission

projects are necessary to facilitate retirement, right?

A. That's correct. I think I also testified that, if generation replacement is on site, on the brownfield site, then there may not be any network upgrades needed.

Q. Okay. Thanks. I think you just answered my next question. Great.

Final coal retirement dates in Duke's Carbon Plan -- proposed Carbon Plan depended on the ability to execute replacement resources and transmission upgrades necessary to ensure or improve reliability, right?

A. That's correct.

Q. For example, the EnCompass model would have endogenously retired Marshall Units 1 and 2 in 2026, but those were moved to 2029 to account for transmission needs, right?

A. That's correct. There's a couple of west port lines between McGuire and Marshall, and based on power flow issues, Belew is one of the lines that overlooks the other one, unless you have a certain amount of Marshall generation online during certain load level -- for certain load levels.

Q. Okay. Thank you. Now I'd like to ask you a little bit about the revised large generator interconnection procedures.

You testified that Duke petitioned FERC for approval of those, right?

A. I testified that we submitted a filing to FERC for approval of a generation replacement process that is similar, very similar to one implemented by Public Service Colorado and Dominion Energy South Carolina.

Q. Thank you for that clarification, that's helpful.

And do you recall those LGIP, do people pronounce that initialism?

A. Yeah, large generator interconnection procedure.

Q. Okay. I'll say it out with you.

You're familiar with the -- with that request that Duke made and the revised attachment K which is the one that applies to DEC and DEP, right?

A. Yes.

Q. You actually submitted testimony to FERC supporting the requests?

A. That's correct.

Q. Okay. Duke filed the petition on June 1st of this year?

A. That's correct.
Q. Okay.
MR. JIMENEZ: Madam Chair, I'd like to move for judicial notice of Duke's request. I have the FERC accession number; would that be sufficient to take notice of the revised LGIP procedures?
CHAIR MITCHELL: Yeah. Let's do this. Can you identify the specific filing -- the title of the specific filing you'd like us to take judicial notice of? I'm not seeing you-all object. But I'd like to know the title of the filing as well as the date and the docket number.
MR. JIMENEZ: Certainly. So what I have is Duke Energy Florida, LLC Submits Tariff Filing Per 35.13(A)(2)(iii), Revisions to Attachments J and K to Joint OATT to be Effective 8/1/2022 Under ER22-2007. And that has accession number in FERC's e-library 20220601-5225.
CHAIR MITCHELL: All right. And the date on which that filing was made?
MR. JIMENEZ: June 1st.
CHAIR MITCHELL: June 1st. All right. Commission will take judicial notice of the filing.
MR. JIMENEZ: Thank you.

Q. And FERC granted that on September 6th, right?

A. That's correct.

Q. Thank you.

MR. JIMENEZ: I'd also like to move for judicial notice of the Order granting that request, if I may.

CHAIR MITCHELL: All right. We'll take judicial notice of the Order issued on August --

MR. JIMENEZ: This was -- it's called -- titled "Order Accepting Tariff Revisions," it's at 180 FERC, paragraph 61156, September 6, 2022.

CHAIR MITCHELL: All right. Commission will take judicial notice of that order.

MR. JIMENEZ: Thank you very much.

Q. At a high level, would it be fair to say that the idea behind Duke's revised large generator interconnection procedures is to make it faster and easier to replace large generating facilities with new generation at the same site?

A. The purpose of that is to allow the customers that have paid for the transmission that's being utilized by the existing generator to retain the rights to that transmission -- interconnection rights to that transmission -- and thus, save on that cost so you wouldn't have to -- I mean, Mr. Snider would probably need to talk with respect to the time it takes -- and I think he went through this, if I remember correctly -- the time it takes from RIP, CPCN, et cetera, for actually siting and building a generator.

Q. Okay. So you wouldn't be comfortable saying that that is even the effect of the revised procedures, to make it easier and faster?

A. Well, you're not gonna have to -- you're not gonna have to wait on some extensive network upgrades, right? So if that speeds it up, that speeds it up.

Q. Okay. In your testimony to FERC about the revisions to the LGIP and the joint OATT submitted on June 1st, you provided an overview of the generator replacement interconnection process, right?

A. I don't have that testimony in front of me. I mean, this is direct testimony on the Carbon Plan proceeding.

Q. That's fair. I have -- I wasn't intending to submit this as an exhibit because I was hoping for judicial notice, but I do have your testimony.

(Pause.)

Q. You know what, I don't. But I do have the

FERC order which has -- summarizes it, the part that I want.

(Pause.)

Q. Okay. Well, can I ask, do you recall your testimony to FERC? Recognizing we're a few months out.

A. Yeah, vaguely.

Q. Okay. If you don't recall, please just -- obviously, that's a fine response.

The revised LGIP process is available only to the owner of the retiring generation, right?

A. That's correct. That's consistent with how FERC has approved the generation replacement process for Dominion South Carolina and Public Service Colorado.

Q. Okay. And do you recall testifying that -- to FERC that Duke changed the definition of replacement generation that Dominion had used in the request that Duke based its request on to make clear that the replacement facility could use different fuel or a combination of fuel types?

A. That's correct, yeah.

Q. Great. Thank you. Okay. I also have a couple pages of the red-lined attachment K. I have the text here, but I can pass those out if folks want to --

I'll do that so we can follow along.

(Pause.)

MS. KELLS: In the interests of time, Chair Mitchell, could we just adopt -- accept the two pages say what they say, unless Mr. Jimenez has specific question about -- the red lines will show the changes.

MR. JIMENEZ: Okay. That sounds fine.

CHAIR MITCHELL: All right. So let's stipulate for the record.

MS. KELLS: We'll stipulate the two pages of Appendix K -- which two pages is it?

MR. JIMENEZ: These are pages 4 and 9.

MS. KELLS: Pages 4 and 9 of the redline to Appendix K that was approved by FERC in the generator replacement proceeding as part of the record.

CHAIR MITCHELL: All right. Please proceed Mr. Jimenez.

MR. JIMENEZ: Okay. I do think I need to cover a couple definitions that are on those pages in order to make these questions make sense. So can we --

Q. Do you recall that, in the revised Attachment

K, a generating facility shall mean an interconnection to a customer's device for the production and/or storage for later generation of electricity, et cetera?

MS. KELLS: Chair Mitchell, if we're gonna ask questions, can the witnesses have a copy? Do you have extra copies? Sorry.

MR. JIMENEZ: Yes.

UNIDENTIFIED FEMALE: Mr. Jimenez, is it the same thing you gave me?

MR. JIMENEZ: There are two different pages.

(Pause.)

THE WITNESS: And did you say this was for the Florida zone or for the DEC and DEP zone? Just to clarify.

Q. My understanding, correct me if I'm wrong, is attachment K is for the DEC/DEP zones.

A. Thank you.

Q. Okay. Can I just point you to the definition of generating facility?

A. Yes.

Q. Okay. On -- then that's on page 4.

Do you agree that it says "and/or storage"?

A. (Witness peruses document.)

Yes.

Q. Okay. And also on page 4, generation replacement, do you agree that it says "and/or storage devices"?

A. Yes.

Q. And the last sentence in that definition says, "The replacement facility may be of a different fuel type or combination of different fuel types," correct?

A. Yes.

Q. And finally on page 9, the definition of replacement generation -- sorry, replacement generating facility shall mean a generating facility that replaces an existing generating facility or a portion thereof at the same electrical point of interconnection pursuant to Section 4.9 of this LGIP.

Did I read that right?

A. Yes.

Q. Excellent. Okay. So multiple generation technologies could qualify as replacement generation under these definitions, right?

A. That's correct. But once again, it says that it needs to connect at the same electrical point of interconnection. And also I'll remind the

Commissioners, with respect to this generation replacement process, that it has to be studied by independent entity, and that study cannot reveal that there is a material impact to the transmission system. If there is, it has to withdraw and go into the DISIS study.

Q. Right. So keeping those caveats in mind, although it's not generation strictly speaking, standalone storage could qualify as replacement generation, could it not?

A. Yes, that's what our filing indicates.

Q. And solar plus storage as well, right?

A. Once again, if there's no material impact and it can connect to the same electrical point of interconnection.

Q. Okay. And in your testimony to FERC, you identified five criteria for the owner of a retiring facility to replace it with a new facility. You've actually anticipated some of that, I think.

Would you agree that none of those criteria require replacement generation to be gas generating?

A. No. But what we do require, from a system reliability perspective -- and this was stated by witness Snider on Tuesday or Wednesday of last week --

is that we show -- and I'll defer to witness Roberts on the Reliability Panel, but what we do show is that in January of 2018, we had some really high capacity factors associated with our coal generators to get through that extended cold weather period.

And so we need to make sure the combined portfolio can reliably meet that need going forward. And so replacement generation is not just about this process, there's a lot of other parameters that need to be met.

Q. Understood. When a coal plant retires, it can be possible to resolve any resulting transmission issues, leaving aside energy and capacity for the moment, with transmission-only solutions, right?

A. Yeah. I mean, you -- if you've got -- especially if you got a lot of megawatts in that area and a lot of potential for other system grid benefits from those resources.

Q. Okay.

A. But yes, sometimes you can't replace the existing generator with just some kind of passive device.

Q. Okay. Are you familiar with the loan guarantee program established in Section 1706 of the

Inflation Reduction Act?

A. I am not.

Q. This is my last handout.

(Pause.)

MR. JIMENEZ: Okay. No further questions.

CHAIR MITCHELL: All right. Tech Customers?

MR. SCHAUER: Thank you, Chair Mitchell.

CROSS EXAMINATION BY MR. SCHAUER:

Q. Craig Schauer on behalf of the Tech Customers. I'd like to pick up where we left off talking about replacement generation. Mr. Roberts, I think these questions are gonna be directed at you. On page 24 of the testimony, starting on line 20 -- well, more generally on page 54.

I'm sorry, 54 of your testimony, you discuss the transmission challenges associated with retiring Duke's coal units; is that correct?

A. That's correct.

Q. And specifically at line 20, you state that, quote, Gabel assumes, for purposes of its report, that all retiring goal generation is replaced on site, and so does not meaningfully engage with this issue; is that correct?

A. That's correct.

Q. Do you happen to have Appendix P with you?

A. Yes, I do.

Q. All right. If I could draw your attention, I'd like to take a look at pages 15 and 16 of Appendix P where it discusses transmission associated with coal retirement.

A. (Witness peruses document.)

Let me find that first.

Q. Sure.

A. (Witness peruses document.)

Q. And halfway through the page, it starts with "DEC," and if you recall, it discusses transmission issues associated with the various coal units; is that correct?

A. Yes.

Q. And it starts with Allen station's Units 1 and 5.

And correct me if I'm wrong, but the Appendix P says that those two units associated with Allen can be retired in December of 2023 in light of current transmission upgrades that are already in progress; is that right?

A. That's correct.

Q. Do you recall, in the Gabel report, that they planned the retirement of the Allen units at the same time as Duke intended the retirement of the Allen units?

A. Subject to check, yes.

Q. All right. I'll save everyone from pulling out that report. The next unit that Duke discusses in Appendix P is Cliffside Unit 5.

And correct me if I'm wrong, but it says that the planning analysis does not identify any major transmission upgrades changes needed for Cliffside Unit 5, correct?

A. That's correct.

Q. And then I'm gonna try to summarize the next few units, and you can please correct me if I'm wrong. But it then goes on to discuss Marshall units, the Belews Creek units, then Roxboro and Mayo. And my understanding of Appendix P is that it says that these coal units would require significant transmission upgrades, but only if replacement generation is not sited at the location of the existing units; is that correct?

A. That's correct. And connected to the same electrical point of interconnection.

Q. Do you recall, in the Gabel report at page 5, that Gabel recommends that Duke use the generator replacement request to recycle existing interconnection facilities by placing new generation on the site of decommissioned generation?

MS. KELLS: Chair Mitchell, if he doesn't have it in front of him, could we get a copy of it in front of him? It's a lot of questions about the Gabel report.

MR. SCHAUER: Sure.

(Pause.)

THE WITNESS: (Witness peruses document.)

Q. All right. And am I correct that, on page 5, Gabel discussed the generator replacement request as a means of replacing new generation on the site of decommissioned coal units?

A. Yes.

Q. All right. And in Appendix P, which we just went through, Duke points to the siting of replacement generation at retired coal locations as a way to avoid transmission challenges otherwise associated with retiring coal units; is that correct?

A. That's correct.

Q. If you can turn to page 17 of the Gabel report.

A. (Witness complies.)

Q. Right above Section 1.2, the last sentence, it says, "Therefore, the Commission should leverage the value of this existing opportunity by directing the Companies to develop a coordinated portfolio-based transmission plan with the NCTPC."

Do you see that?

A. Yes.

Q. Do you recall reading that in the Gabel report as you prepared your testimony?

A. Yes.

Q. And do you recall, in Duke's verified petition, that the fifth request for relief asked that the Commission, quote, direct the Companies to continue to study future transmission needs to reliably implement the Carbon Plan through the NCTPC and other appropriate forums?

A. Yes.

Q. A few more questions. Moving on to page 59 of your testimony, there it discusses that Duke analyzed increasing import capability of off-system

purchases.
Do you recall that testimony?
A. Yes.
Q. So the testimony identifies a feasibility study of a transfer of 1,500 megawatts of power from PJM and -- between PJM and DEP.
Do you recall that study?
A. Yes.
Q. And if I'm correct, the feasibility study showed that the need -- showed a need to make upgrades requiring significant time and expense with an initial cost of approximately $700 million; is that right?
A. That's correct. We utilized the PJM deliverability -- generation deliverability tool, or application, and PJM input data to conduct that analysis and other affected system studies, other study inputs to perform that analysis.
Q. And then at page 60, you also point to a 2019 feasibility study regarding importing onshore wind into PJM, which showed upgrades costing, I believe, $411 million.
Do you recall that feasibility study?
A. Can you point me to the line?
Q. I believe it's --

A. Yeah, I see it.
Q. Yeah. Line 16 through 19?
A. Yes. Into DEC, yes.
Q. Right. So that was a second feasibility study that you conducted between one of the Companies and PJM?
A. That was a request, a study request submitted to PJM. PJM conducted that study and provided those results.
Q. Earlier on page 60, at line 4, you discuss that you submitted a transmission service request to the PJM queue, and you were awaiting its results; is that right?
A. That's correct.
Q. So that would be a third study requested but not yet completed?
A. That would be something to validate the results of our internal analysis and confirm the duration and confirm the cost or deny both of those. Give us the up-to-date cost and duration for upgrades needed to import.
Q. And that was between the Companies and PJM, correct?
A. That's correct.

Q. All right. The testimony makes no mention of conducting a feasibility study for transferring additional power from the Tennessee Valley Authority; is that correct?

A. That's correct.

Q. Likewise, it makes no mention of conducting a feasibility study for the transfer of power from Southern Company, correct?

A. That's correct.

Q. According to Appendix C, at page 2, you might know this off the top of your head, Duke has 78 tie-line circuits connecting it with 10 different transmission operators; is that right?

A. Subject to check, yes.

Q. And am I correct that Duke studied two transmission options with a single neighboring balancing area being PJM, and based on those two studies, Duke has concluded that the remaining 76 tie-lines are uneconomic to make additional off-system purchases?

A. So in the 2020 IRP, we looked at other interfaces like Southern Company. And for this Carbon Plan, as directed by the Commission in the 2020 IRP, we were to specifically look at a capacity purchase from

PJM.

Q. Do you make reference to those other interfaces studied as part of the 2020 IRP in your testimony?

A. No, I do not.

Q. Right. Are they referenced elsewhere in the Carbon Plan?

A. I don't believe so.

Q. All right.

MR. SCHAUER: No further questions, Chair Mitchell.

CHAIR MITCHELL: All right. Perfect timing. All right. We are done for the day. As a reminder, we will be back here in the morning at 9:30, and we will begin with Walmart. All right. With that, we'll be off the record. Thanks.

(The hearing was adjourned at 5:00 p.m. and set to reconvene at 9:30 a.m. on Tuesday, September 20, 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 22nd day of September, 2022.

Joann Bunze

JOANN BUNZE, RPR
Notary Public #200707300112