PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Monday, June 17, 2024

TIME: 10:03 a.m. to 2:12 p.m.

DOCKETS: E-100, Sub 190

BEFORE: Commissioner Karen M. Kemerait
Chair Charlotte A. Mitchell
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner William M. Brawley
Commissioner Tommy Tucker

IN THE MATTER OF:

Technical Conference

Biennial Consolidated Carbon Plan and Integrated Resource Plans of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, Pursuant to N.C.G.S § 62-110.9 and § 62-110.1(c)

Noteworthy Reporting Services, LLC

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

FOR DUKE ENERGY PROGRESS, LLC, AND
DUKE ENERGY CAROLINAS, LLC:
Hayes Finley, Esq.
410 South Wilmington Street, NCRH 20
Raleigh, North Carolina 27601

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

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY
RATES II AND III:
Christina D. Cress, Esq.
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

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

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

FOR AVANGRID RENEWABLES:

Benjamin W. Smith, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

FOR CAROLINAS CLEAN ENERGY BUSINESS ASSOCIATION:

John D. Burns, Esq.
811 Ninth Street, Suite 120-158
Durham, North Carolina 27705

Ben Snowden, Esq.
Gordon Smart, Esq.
Fox Rothschild, LLP
434 Fayetteville Street, Suite 2800
Raleigh, North Carolina 27601

FOR ENVIRONMENTAL DEFENSE FUND:

Benjamin W. Smith, Esq.
Kilpatrick Townsend & Stockton LLP
4208 Six Forks Road, Suite 1400
Raleigh, North Carolina 27609

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

TRACT CAPITAL MANAGEMENT, LP:
Daniel R. Simon, Esq.
Nelson Mullins Riley & Scarborough, LLP
301 South College Center, 23rd Floor
Charlotte, North Carolina 28202

FOR CLEAN ENERGY BUYERS ASSOCIATION:
Kurt J. Olson, Esq.
Post Office Box 10031
Raleigh, North Carolina 27605

Grant Snyder, Esq.
Keyes & Fox, LLP
1580 Lincoln Street, Suite 1105
Denver, Colorado 80203

FOR APPALACHIAN VOICES:
Andrea C. Bonvecchio, Esq.
Law Offices of F. Bryan Brice, Jr.
130 South Salisbury Street
Raleigh, North Carolina 27601

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

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, NATURAL RESOURCES DEFENSE COUNCIL, SOUTH CAROLINA COASTAL CONSERVATION LEAGUE, SIERRA CLUB, NORTH CAROLINA JUSTICE CENTER, AND NORTH CAROLINA HOUSING COALITION (SACE ET AL.):

David Neal, Esq.
Nicholas Jiminez, Esq.
Thomas Gooding, Esq.
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Ethan Blumenthal, Esq.
4441 Six Forks Road, Suite 106-250
Raleigh, North Carolina 27609

Justin T. Somelofske
Sierra Club
50 F. Street, NW, Eighth Floor
Washington, DC 20001

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

ON BEHALF OF THE UNITED STATES DEPARTMENT OF DEFENSE AND ALL OTHER FEDERAL EXECUTIVE AGENCIES:

John J. McNutt, Esq.
U.S. Army Legal Services Agency
9275 Gunston Road
Fort Belvoir, Virginia 22060-5546

FOR THE OFFICE OF THE ATTORNEY GENERAL:

Tirrell Moore, Esq.
North Carolina Department of Justice
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE PUBLIC STAFF ON BEHALF OF THE USING AND CONSUMING PUBLIC:

Nadia Luhr, Esq.
William E. H. Creech, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

P R E S E N T E R S:

FOR PUBLIC STAFF:

Dustin R. Metz, Manager, Electric Section - Operations and Planning, Energy Division

Jeff Thomas, Public Utilities Engineer III, Energy Division

FOR THE OFFICE OF THE ATTORNEY GENERAL:

Edward Burgess

FOR CAROLINA INDUSTRIAL GROUP FOR FAIR UTILITY RATES II AND III:

Brian C. Collins

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:

Dr. John O'Brien

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

Jake Duncan of Vote Solar

Michael Goggin of Grid Strategies, LLC

P R E S E N T E R S (Cont'd.):

FOR ENVIRONMENTAL DEFENSE FUND:

Josh Kaplowitz

William (Bill) B. McAleb

FOR TOTALENERGIES:

Matthew W. Tanner, PhD Managing Director, Berkeley Research Group, LLC

FOR AVANGRID RENEWABLES:

Mical Nobel

Elizabeth (Betsy) Andrews

Jeffrey Bower

FOR TRACT CAPITAL MANAGEMENT:

Ronald J. Moe, Vice President of Energy and Infrastructure Consulting, Leidos Engineering, LLC

FOR CAROLINA ENERGY BUSINESS ASSOCIATION:

Michael Hagerty

Nicole Miller

Sam Newell

P R E S E N T E R S (Cont'd.):

FOR CLEAN ENERGY BUYERS ASSOCIATION:

Jennifer Chen, World Resources Institute

Ivan Urlaub, Principal, Urlaub Strategies

FOR APPALACHIAN VOICES:

Evan Hansen, Downstream Strategies, LLC

P R O C E E D I N G S

COMMISSIONER KEMERAIT: Good morning. Okay. Good morning. Let's come to order and go on the record, please. I'm Karen M. Kemerait, a Commissioner on the North Carolina Utilities Commission. And with me this morning are Chair Charlotte Mitchell; Commissioners Kimberly W. Duffley, Jeffrey A. Hughes, Floyd B. McKissick, Jr., William M. Brawley and Tommy Tucker.

On January 17, 2024, the Commission issued an Order in the Biennial Consolidated Carbon Plan and Integrated Resource Plan of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC, pursuant to North Carolina General Statute Sections § 62-110.9 and § 62-110.1(c). And I will call this the CPIRP Docket going forward.

And the CPIRP Docket, among other things, scheduled a technical conference to occur on this date and time for the purpose of receiving oral presentations with an opportunity for Commissioners to ask questions on the testimony of the interveners on Duke's proposed 2023 CPIRP. The Order limited participation in the technical conference to the intervening parties in the CPIRP

Docket that filed expert witness testimony and required those participants to file a list of individuals who will appear at the technical conference, as well as any presentation materials.

The intervening parties participating in today's technical conference are and will appear in the order as listed as follows: The Public Staff, the Attorney General's Office, the Carolina Industrial Group For Fair Utility Rates I, II and III, the North Carolina Sustainable Energy Association, the Southern Alliance For Clean Energy, the Environmental Defense Fund, TotalEnergies, Avangrid Renewables, Tract Capital Management, the Carolina Clean Energy Business Association, the Clean Energy Buyers Association and Appalachian Voices.

On May 1, 2024, the Commission issued a Procedural Order directing that each participating entity or group of entities participating as a consolidated group be limited to 15 minutes of presentation time, with the exception of the Public Staff, which will be limited to 30 minutes of presentation time.

The Commission will adhere strictly to

the time limits outlined in the May 31, 2024 Order. The Commission therefore asks that each participating intervenor pay close attention to the 15-minute time limit and not exceed the time limit. I will also be monitoring the 15-minute time limit and will let any participating intervenor know if the 15 minutes has expired.

I now call upon counsel for the parties to introduce themselves for the purposes of the record beginning with Duke and then the Public Staff.

MS. FINLEY: Good morning, Presiding Commissioner Kemerait. My name is Hayes Finley appearing on behalf of Duke Energy.

COMMISSIONER KEMERAIT: Good morning.

MR. BREITSCHWERDT: Good morning, Presiding Commissioner Kemerait and Members of the Commission. Brett Breitschwerdt with the Law Firm of McGuireWoods on behalf of Duke Energy Carolinas and Duke Energy Progress.

COMMISSIONER KEMERAIT: Good morning.

MS. LUHR: Good morning. Nadia Luhr with the Public Staff on behalf of the Using and Consuming Public, and also appearing with me today is Zeke Creech with the Public Staff.

COMMISSIONER KEMERAIT: Good morning.

MR. MOORE: Good morning. Tirrill Moore with the North Carolina Attorney General's Office. I'm joined today by my colleague, Derrick Mertz.

COMMISSIONER KEMERAIT: Good morning.

MR. SMITH: Good morning. Ben Smith from Kilpatrick. I represent Avangrid Renewables and the Environmental Defense Fund.

COMMISSIONER KEMERAIT: Good morning.

MR. NEAL: Good morning, Presiding Commissioner Kemerait. David Neal with the Southern Environmental Law Center. With me is Nicholas Jiminez and Thomas Gooding on behalf of Southern Alliance For Clean Energy, Natural Resources Defense Council and the Sierra Club, which we'll call SACE et al.

COMMISSIONER KEMERAIT: Good morning.

MS. GRUNDMANN: Good morning, Your Honor. On behalf of Walmart, Inc., Carrie Grundmann from the Law Firm of Spilman Thomas & Battle.

COMMISSIONER KEMERAIT: Good morning.

MS. GRUNDMANN: Good morning.

MR. SOMELOFSKE: Good morning, Commissioner Kemerait. On behalf of North Carolina Sustainable Energy Association, Justin Somelofske and I'm joined by my co-counsel, Ethan Blumenthal.

COMMISSIONER KEMERAIT: Good morning.

MS. BONVECCHIO: Good morning, Commissioners. My name is Andrea Bonvecchio. I'm with the Law Offices of Bryan Brice and I'm here on behalf of Appalachian Voices.

COMMISSIONER KEMERAIT: Good morning.

MR. BURNS: Commissioner, John Burns with the Carolinas Clean Energy Business Association. I'm joined in this docket by Ben Snowden and Gordon Smart of Fox Rothschild.

COMMISSIONER KEMERAIT: Good morning.

MS. CRESS: Good morning, Presiding Commissioner Kemerait. Christina Cress with the Law Firm of Bailey & Dixon appearing here on behalf of CIGFUR II and III.

COMMISSIONER KEMERAIT: Good morning.

MR. OLSON: Good morning. I am Kurt Olson. I am acting as local counsel for the Clean

Energy Buyers Association and I am with Grant Snyder who is their counsel and will be presenting with us.

COMMISSIONER KEMERAIT: Good morning. For any other appearances, can you please step to a microphone so that it can be recorded.

MR. OLSON: Okay.

COMMISSIONER KEMERAIT: Thank you.

MR. McNUTT: Good morning. John McNutt on behalf of the United States Department of Defense and All Other Federal Executive Agencies.

CHAIR MITCHELL: Okay. Good morning.

MR. SIMON: Good morning. I'm Daniel Simon with the Law Firm Nelson Mullins Riley & Scarborough. Thank you.

COMMISSIONER KEMERAIT: Who are you representing?

MR. SIMON: I'm so sorry. I'm here on behalf of Tract Capital Management, LP. Thank you.

CHAIR MITCHELL: Thank you. Good morning. Are there any other attorneys who need to make an appearance?

(No response.)

COMMISSIONER KEMERAIT: With that, are there any procedural matters that we need to address before we get started?

(No response.)

COMMISSIONER KEMERAIT: Okay. Seeing none, we'll go ahead and get started and we will begin with the Public Staff.

MR. THOMAS: Good morning, Commissioners. My name is Jeff Thomas. I'm an engineer with the energy division of the Public Staff. And with me today is Dustin Metz, the manager of the operations and planning section of the energy division.

We are going to go through our presentation just to give you a brief overview, talk through some of our key takeaways, talk a little bit through some of the testimony that was filed by the witnesses by the Public Staff.

MS. LUHR: And if I can -- Mr. Thomas, really quickly -- Presiding Commissioner Kemerait, we do also have in the room the other witnesses who filed testimony in this proceeding for the Public Staff: Witnesses Lawrence, Williamson, Michna, Hinson, Fahey, Nader and Boswell. And if the Commission does have any questions related to their specific subject matter, they are available to come up to the stand.

COMMISSIONER KEMERAIT: Thank you. But those witnesses will not be additionally presenting this morning; is that correct?

MS. LUHR: That is correct.

COMMISSIONER KEMERAIT: Okay. Thank you.

MR. THOMAS: Okay. So I'll just start at the top with some of the Public Staff's key takeaways. So our testimony is quite lengthy and is supported by a deep investigation of Duke's both August 2023 CPIRP filing, as well as the January supplemental planning analysis.

Duke presents in that portfolio a recommended portfolio with an interim compliance date of 2035. Based on our investigation, we looked many different interim compliance years input to the model of assumption. We believe that Duke that should pursue interim compliance by 2034, and that decision drives a lot of the recommended changes we made to their near-term action plan, as well as other modeling inputs throughout the planning horizons.

Our own modeling as well as Duke's modeling do suggest that interim compliance by 2030 or 2032 could require unreasonable amount quantities of new resources interconnected at the time of significant load growth and retirement of existing coal generation. Our near term action plan contains some slightly higher targets for solar, onshore wind, and advanced nuclear, and a more cautious approach on natural gas, and for reasons that we will describe in our testimony and later in this presentation.

We also believe that Duke should continue to focus on measures to increase interconnection capability above and beyond the measures that they are already taking. We detail that in our testimony as well. And we do believe that a particular focus on the near term on solar plus storage would be prudent and save costs -- reduce costs for ratepayers.

We do find that the Duke's proposed near-term development activities for long-lead-time items such as Bad Creek II, the expansion of the pump storage facility in South

Carolina, advanced nuclear and offshore wind are reasonable -- are generally reasonable, although we do find that the offshore wind acquisition requests for information that Duke proposes in its supplemental planning analysis should be better to find with a more reasonable path to commercialize -- to advancing development while simultaneously protecting ratepayers from cost overruns.

Next slide. I'll pass it to Dustin Metz to talk about our near-term action plan.

MR. METZ: I'm looking at the table at the bottom of the slide. The Public Staff has some minor differences to Duke in regards to the near-term action plan. But generally, they're very similar.

The high or low forecast coupled with increasing solar penetrations will require more energy storage in order to best utilize that resource. At this time, uncertainty exists with larger volumes of natural gas generation given the recent EPA 111 Rule and the declining capacity factors of the generation assets over the life of the asset.

If more large load seeks to locate in

Duke's service territory, target volumes in the Public Staff's near-term action plan may need to be adjusted upward. At the same token is, if some of the load does not manifest itself, some of the procurement targets in the Public Staff's near-term action plan could be minorly adjusted downward.

Going a little bit over some of the technologies highlighted in bold in the graph. In looking at solar, there's a slight increase in our proposals, as Mr. Thomas's testimony discussed in more detail and some of those actions that could be taken in order to leverage cost savings. However, our modeling does show more energy storage is needed.

Transitioning to onshore wind, our model sensitivity showed a rather robust selection of the technology. However, there still are some unknowns on the timing of those assets and whether or not we can achieve the energy values that are estimated within the modeling forecasts.

Shifting to combined cycles. As I stated earlier, there is still uncertainly with the potential EPA 111 compliance.

Then lastly, advanced nuclear. Portfolios that have accelerated advanced nuclear have the lower overall costs in PVRR, coupled with other benefits such as overall lower carbon intensity of compared to other portfolios.

COMMISSIONER KEMERAIT: Mr. Metz, real quickly, did you mean to mention something about the combustion turbines as well? I heard you talk about the CCs but not the CTs.

MR. METZ: The combustion turbines are similar to overall combined cycles. However, given the combined cycles before EPA 111, compliance would normally operate between a 75-to-80 percent annual capacity factor. Those getting reduced potentially to 40 percent as will be discussed later in my slide deck, is more impactful than the simple cycle combustion turbines.

However, simple cycle combustion turbines still will require EPA 111 plan compliance by the Utility, because if left unlimited within the model or dispatch, they would run or have the possibility of running higher than a 40 percent annual capacity factor.

COMMISSIONER KEMERAIT: Thank you.

MR. METZ: Shown on this graph are the overall portfolio costs. Over on the right-hand side is a chart showing the relative scale of the PVRR for Duke's plans, which are the top three in orange, followed by the Public Staff portfolios in blue. Earlier compliance equals higher cost. Later compliance equals less risk and may have minor impact to the actions listed in the Public Staff's near-term action plan.

It is worthwhile noting that there are similar costs of multiple portfolios at or near the approximately $150 billion PVR impact amounts. And you see in looking at the graph on the slide deck, if you look at Duke's P3 fall base is approximately $150 billion followed by the last five of the Public Staff's modeling sensitivities. For my view, this illustrates there are multiple pathways with similar costs to achieve the the compliance states. We are just getting there in different ways.

It's also important to note that these cost estimates listed in the PVR graphs do not capture all of the Utility's costs and there will be other cost increases that are sought for general recovery in general rate cases.

Mr. Thomas?

MR. THOMAS: Sure. If we move to the next slide. So as Mr. Metz pointed out, present value of revenue requirements for PVRs is a single number that can be helpful in determining the relative scale of the build-out and the timing, right. Further out costs are discounted further and so they have less of an impact on the total PVRR.

Another method that Duke uses and the Public Staff uses as well to analyze our portfolios is estimated retail bill impact. So both within Duke's testimony and filing and the Public Staff's filing, we've attempted to estimate the bill impact of our portfolio with a 2034 compliance, which you can see here in blue, to Duke's recommended portfolio P3 fall base which has a 2035 compliance date, and Duke's P2 fall supplemental portfolio with a 2023 compliance date.

So we try to put these in context. And I will note that our attorneys are currently working on a correction to these charts where there was a miscalculation in the Public Staff's estimates of its own portfolio analysis. I'll talk a little bit through some of that analysis. But generally, it would put our portfolio slightly less of a bill impact, particularly in DEP. That filing will be coming shortly.

But generally, there is still a lot of close resemblance among these portfolios as you go out over time. And again, as Mr. Metz noted, this doesn't capture all the costs. For example, distribution costs that you might find in the multi-year rate plan, those are not included here. This is simply the new generation, the cost of the retiring generation and the cost of operating the system; more or less fuel burning, operations and maintenance costs, major repairs and transmission infrastructure.

COMMISSIONER KEMERAIT: And Mr. Thomas, you stated -- you just said that the filing would be coming shortly. You're referring to the corrected -- the correction, and you'll be filing corrected information shortly.

MR. THOMAS: Yes. Essentially, these

two graphs corrected in Williamson Exhibits 5 and 6. So we're working on that. There was -- during discovery, we found an error in some of our treatment of investment tax credits, which will reduce our bill impacts relative to what they are showing here.

COMMISSIONER KEMERAIT: Thank you.

MR. THOMAS: Of course. And you know, just simply to note, you know, over the long term, you know, in particular in DEP, our portfolio selected significantly more offshore wind, for example. So you can see that it does increase that cost while that's being deployed. But those result in production cost savings later on in the portfolio that help to level out that cost increase.

So there's a lot at play here: The timing of resource deployment, how it's recovered, over what time period and the operational savings it can provide. But it is a complex picture and these bill impacts hopefully help paint a picture of these different portfolios.

Moving to the next slide. So obviously, as the ratepayer advocate, cost for us is a major concern, right. We deal with customers that have trouble paying their bills. And so we -- we believe that, you know, we can implement this plan will have costs but there are ways to control costs; incremental steps that Duke can take to be more cost effective with the resources they have and to reduce the bill impact to the greatest extent possible.

For example, one proposal outlined in my own testimony and Witness Boswell is that Duke should take -- take advantage of -- aggressive advantage of the Energy Infrastructure Reinvestment Loan Program operated through the Department of Energy. Our own modeling which only considers some of the benefits and doesn't necessarily capture all of the potential compliance costs suggests that aggressive application for EIR funding could save ratepayers hundreds of millions of dollars over the next ten years and could even result in cost-effective deployment of additional resources over and above what is already being planned.

We also believe that Duke should continue to seek creative solutions for interconnection bottlenecks and costly transmission upgrades which have been an issue in this state for some time now. Some examples in my testimony are potentially competitive procurements to re-power existing qualifying facilities that have been operating for -- for close on a decade now and are coming up on the end of their PPA terms.

Some of these facilities could be cost-effectively re-powered without triggering transmission upgrades. And also, potentially siting solar or storage or even wind at the site of fossil sites. You know, a combustion turbine is only operated some certain number of hours per year. That surplus interconnection capacity can provide a significant benefit of clean energy in furtherance of HB 951's goals while not triggering those expensive upgrades that Greenfield Solar often does.

These are -- there's no silver bullet to the interconnection challenges kind of facing us in this state. But there are many incremental steps that, taken together, can help us get there without needing to continually build out our transmission system.

MR. METZ: Continued integration of the transitioning energy fleet will require new transmission in order to maintain reliability. The recent Carolinas Transmission Planning and Collaborative Public Policy Study coupled with expected Duke Energy Progress to Duke Energy Carolinas power flows are starting to show stress points on the the overall transmission system.

The Public Staff's near-term action plan laid out a series of actions for offshore wind. It is worthwhile noting that should the Commission choose to delay interim compliance, it does start shifting out the need to move faster on potential offshore wind deployment.

We need to define a series of actionable steps and promote a conducive, fitting environment for future long-lead-time resources. And we need to have a heart-to-heart discussion on cost certainly and risk sharing for these long-lead-time resources in order to leverage and protect ratepayers from cost unknowns.

COMMISSIONER KEMERAIT: And Mr. Metz, before you move on, I did have a question about your -- let's see -- fourth bullet point about cost-effective projects that can ensure reliability issues or timely interconnection of metered resources. Can you give an example of what you're referring to?

MR. METZ: So looking at overall holistic transmission planning to the extent as we identified, just again from a hypothetical, if we say if X amount of solar generation resources need to be built in, say, Duke Energy Carolinas and if the Company has projected a need for natural gas generation and Duke Energy Carolinas, there could be ways that we can implement transmission projects that can lever synergies off one another.

If we build natural gas generation in areas that are already transmittance-constrained, however, there's limits to how far we can move away from Transco, we may need to upgrade segments of overall transmission system to allow that input of the generation resource.

When the Company -- again, in a hypothetical -- when the Company is evaluating the sizing of that facility, we can also project how much solar or other generation resources would be needed in bill of the transmission line once. However, in doing that type of holistic study, we also have to evaluate -- it could take one year longer to build out all those transmission projects, but you'll have more certainty to reduce the bottlenecks as Mr. Thomas talked about slightly earlier.

COMMISSIONER KEMERAIT: Thank you.

MR. THOMAS: So moving to the next slide, we wanted to briefly go over load forecast. So, you know, load forecast in addition to the interim compliance savings is essentially the major driver of all investment decisions. If the load was going down, we wouldn't have to build nearly as many resources. But it's not, and we have, in fact, rapid development of new economic customers both in North and South Carolina. The Toyota EV factory here in North Carolina, the BMW expansion in South Carolina, data centers coming; any high-impact load customers -- very high load factors so they're almost running at full tilt all the time.

And this is relatively new for the Carolinas, right. Duke's normal, organic load forecast projection, you know, used complex regression models to look at class, you know, residential, commercial, industrial load forecasts over time. And we refer to this as this organic load forecast. They've been doing this for decades.

I don't have -- that regression analysis looks back at history to predict the future. With this change, these new customers, that's no longer really viable to necessarily predict where those load customers are coming and how large they will be.

So Duke worked to develop kind of an independent methodology to essentially add separately these customers to the load forecast using a variety of, you know, thresholds for, you know, how far along developed are they? How sure are we that they're coming? What's the delay factor? And they added these loads to the normal, organic load factor forecast.

And so, we and other intervenors have raised some concern about, A, potential double counting, right. So if some of these loads are already showing up in economic growth projections, they're going to show up in your commercial/industrial load forecast because those take into account your economic load growth. But these are unique loads, so it's possible that it wouldn't capture everything if you didn't manually add them back.

So, you know, but we've also noticed that there is a lot of uncertainty. There's not a lot of data that we have in North Carolina that we can compare to to say, "Well, this customer looks a lot like these other customers and I don't think they're actually going to ever break ground."

So we've seen, even in the update between January and April, that some of these large load customers are dropping out, withdrawing or delaying. And we're seeing this pushback particularly in DEP.

So, you know, we've worked through the data to impart/develop a potential sensitivity, an alternative load forecast that eliminates the effect of the double counting. But, you know, the takeaway here, because this is something that's being worked on and challenging utilities both in Virginia and Georgia and across the southeast.

And so we recommend that Duke continue to really monitor those loads, these large customers, both in our areas and in neighboring areas experiencing the same issues; that they continually update the Commission with changes to this load forecast, new customers, customers dropping out and that type of thing; and then also to continue to improve and use probabilistic models to evaluate this load and the certainty with which will come and continue to update those models with things that we've learned, both in this jurisdiction and similar jurisdictions.

Next slide. And so that is the gross load forecast. That is -- essentially, this is the megawatt hours that will be required by the customers here. But then we have load modifiers, so grid edge, rooftop solar, electric vehicles, tariffs in energy efficiency; all of these affect the load forecast.

So we've looked through those, and as summarized in Witness Williamson's testimony, it's generally agreed that the forecasts are generally reasonable. We do make some recommendations with regard to demand site management, which can be called upon by the system, similar to its DET, subject to the the parameters of the program as a supply site resource. And we recommend that Duke explore and future a carbon plan, potentially modeling new programs to determine their potential impact in savings, to help refine its program development.

And then also, we recommend that Duke begin developing some equivalent to power repair for nonresidential customers, which is essentially incentivizing the Utility -- the Utility to provide incentives for these companies to build solar and storage or other resources, and then those resources can provide system benefits by allowing Duke to dispatch these -- particularly the storage resource -- in times of high grid demand.

So -- but either way, this -- these forecasts require continually to check and adjust to see what kind of energy efficiently these new large load customers might come on or what creative tariffs or other collaborative programs between the Utility and these large customers can produce for the system.

MR. METZ: One of the takeaways from the Public Staff analysis is that some form of new natural gas is going to be recommended, but there's qualifiers, as discussed extensively through multiple Public Staff witnesses' testimonies, and to be built in the Carolinas.

By the final EPA 111 Rule did not include hydrogen, per se, as the best system of emission reduction. That does not mean that we should not continue the discussions about the technologies that impact the system. If hydrogen will be used in the future, we need to start evaluating and counting that load in order to generate that fuel. Hydrogen will not be produced in an island.

The existing coal fleet is aging. However, Duke should continue to evaluate to make sound decisions in maintaining their existing fleet while striving towards interim compliance.

If the EPA 111 Rule is not overturned, Duke Energy Progress's coal plants may need to be retired slightly earlier than expected, which would have influence on the near-term action plans.

One large takeaway from this slide is just 40 percent. Just trying to drive that home. New combined cycles that will be built, to the best information that the Public Staff has as of right now, will have to be operated at approximately half of their expected annual capacity values.

That does impact the economics of these natural gas assets that however, with one of the Public Staff sensitivities, it still did select the resources. However, it is the location in which they're being selected and the timing of how they're being selected.

The Company will need to -- or the Company -- Duke will need to file or somehow summarize of what their ultimate plan will be for EPA 111 compliance.

COMMISSIONER KEMERAIT: Mr. Metz, let me -- let me ask a clarifying question. You just mentioned that it's critical to consider location and timing in regard to the new rule. Could you explain that a little bit more?

MR. METZ: Yes. Thank you. So one of the items that the Public Staff identified is where should the resources be built in regards to should they be built in DEC or should they be built in DEP? My testimony showed the overall power flows are occurring from DEP to DEC and how those values are approximating up to 25 or 26 percent.

To give that a context, that Duke's model run showed that approximately 25 percent of the energy produced in Duke Energy Progress under their P3 fall base is but to serve, economically, Duke Energy Carolina's load. The Public Staff modeling with some of the changes that we've made shows a shift of combined cycle location from -- instead of the combined cycles being built in DEP, to be built in DEC. DEC has more load growth relative than Duke Energy Progress.

Did I answer your immediate question?

COMMISSIONER KEMERAIT: It did. And then, could you explain timing? You mentioned timing as well.

MR. METZ: Yes. The overall timing will be coupled with -- when the resources are needed, of course -- when there is a strong correlation of when units retire, existing coal generation units retire, combined cycles are typically being built.

So what does that mean? So if the company was to potentially delay a coal retirement for economic reasons or other factors, it could potentially impact the need to display or defer the combined cycle by a year. But at the same token is if new risks are unknown start manifesting themselves with some of these older generation assets, we may need to evaluate in potentially moving those projects up accordingly.

COMMISSIONER KEMERAIT: Thank you.

MR. METZ: And maybe to one last point. It was also that we were seeing a shift in some of our sensitivities from some of the combined cycles being shifted out; nominally, the fourth and fifth and sometimes sixth cycles shifting out to 2034, plus or minus.

So what does that mean? That may mean that we don't necessarily have to make those decisions today in this carbon plan for potential CPC applications and those can be checked and adjusted until the next carbon plan proceeding.

MR. THOMAS: And can I just put a finer

point on that. You know, I think witness Michna kind of goes over this extensively in his testimony that Duke's near-term action plan potentially calls for seeking five CPCNs prior to the next -- the 2025 Carbon Plan Order which will come out at the end of 2026.

And we, as I said before, we are believing that that -- we need to be more cautious there. Because this is a lot of money to spend on assets that may only run 40 percent of the time, depending on how the EPA rolls out and how the load forecast comes.

And that's kind of what, you know, Dustin is talking about, right. It's kind of pumping the brakes a little bit and saying this is a risky asset at this juncture and let's -- let's see what we need. And it may be that they are needed. But we are worried that these costs could become stranded for ratepayers and lock them in over the -- the next 35 years.

MR. METZ: And also, to be transparent and, I believe, fair, that EPA 111 Rule dropped after Duke filed its P3 fall base. EPA 111 Rule dropped just a very short time before the Public

Staff filed its testimony.

So I think everyone needs to kind of step back and reflect on what the EPA 111 tax means for these future natural gas resources.

MR. THOMAS: Public Staff's recommended 2034 interim compliance date and near-term action plan seek a balance of least cost planning, grid reliability and execution risk. Overall, we consider the Public Staff's proposal to be aggressive but not impossible.

Duke must take reasonable steps while also moving aggressively on new resources in both the near and long term to ensure a reliable grid, long-lead-time resources, create an interesting impact on the near-term action plans that need to be made today inclusive of transmission. And that's an important point also to note that new generation assets and transmission need to be had in the same discussion. They can't be independent of one another.

Planning for carbon neutrality in the face of significant uncertainty will require frequent adjustments and refinements, some of which will need to take place outside of the two-year CPIRP cycle. We need a degree of flexibility to adjust to changes in expected load, future energy regulation, as we've seen with EPA 111, and leverage all opportunities to decrease costs.

And Mr. Thomas, if you'd like anything to add?

MR. THOMAS: I think that's -- Mr. Metz summarized it fairly well, and that's what our testimony tries to get at is that we want to protect ratepayers while following the law and implementing it and making sure that we aren't locking ourselves into a path where we'll have lots of regrets later on. So thank you.

COMMISSIONER KEMERAIT: Thank you, Mr. Thomas and Mr. Metz for your informative presentation. And let me check with the Commissioners to see if we have any clarifying questions.

COMMISSIONER DUFFLEY: I just have --

COMMISSIONER KEMERAIT: Commissioner Duffley.

COMMISSIONER DUFFLEY: You were talking about the EPA rules. It's just a procedural question. Will you be working with this DEQ regarding state implementation plans or touching base with DEQ regarding what North Carolina's going to be doing?

MR. METZ: Yes. We have had conversations with DEQ and we continually to try to -- well, not try to -- we continually to have conversations with them to see what their overall implementation plan will be.

COMMISSIONER DUFFLEY: Thank you.

MR. THOMAS: And can I just add to that? However, our -- our impression from our discussions with the North Carolina DEQ is that the state implementation plan will largely address existing coal and how to handle that. But the -- the rules for new natural are not decided by the implementation plan. Those are effective with the -- the finalization of the rule.

COMMISSIONER DUFFLEY: Thank you.

COMMISSIONER KEMERAIT: Commissioner Hughes.

COMMISSIONER HUGHES: Thank you, very much. This is just to understand the framework of analysis for you and for -- and to allow the different intervenors. From a least -- the definition least cost, which is not really that closely defined anywhere, it seems like for Public Staff, the two -- the two cost metrics in your presentation and in your testimony are the present value of revenue requirements and the bill impacts.

Am I missing any other least cost or are those the two kind of overarching metrics that we should be paying attention to?

MR. THOMAS: In terms of cost, yeah. I think those are the two major indices that we are looking at.

COMMISSIONER HUGHES: And then could you just -- just say really briefly how you view the two of those in general terms, what they are? I mean, I think they could be interpreted as different things. Can you just kind of walk through the two of them and just describe what are some of the things that went into them? How are they done? That sort of the thing.

MR. THOMAS: Sure. Yeah. I can take it and, Mr. Metz, and if you want, so -- so the PBR essentially is the starting point. And you take modeling output files from there and that looks at, you know, like, the cost of production -- the production costs -- that's fuel -- and operations management cost. It takes into account the tax credits for new resources, both production tax credits and investment tax credits for eligible resources.

In our case, it took into account some of the energy infrastructure reinvestment act savings that would reduce the costs, the revenue requirement of some of these. And then that -- those costs of all that new generation, operating the new generation, the new transmission that's kind of baked into it -- all of that is kind of put into this model that essentially estimates the company's revenue requirements each year.

So taking into account the allocation to retail of these customer -- of the bill impacts that -- well, that's for the bill impact. But it takes into account the the cost of capital, the weight of the average cost of debt, the cost of equity, the capital structure. And it essentially estimates this and then brings back that kind of cash stream of revenue requirements back to the present.

And so there's a lot of uncertainty around there. And I think that it's, you know, it's easy to look at a list of, you know, portfolios and say, "Well, let's just pick the lowest one and go ahead." And I think PBR doesn't -- what it doesn't capture right is, first of all, lots of uncertainly baked throughout, right. So there's a little bit of a margin of error, you could say, to each of these portfolios.

But importantly, what it doesn't capture is a lot of things like stranded asset risk, right. What happens if we build a plant today and it -- you can't operate nearly what it's projected to operate. It doesn't provide that energy value. So we have to go couple it with something else and maybe it's not the the best resource at that point.

It doesn't capture a lot of the -- maybe the nuances of, you know, failures at certain sites and what happens, you know, when -- when there's a disaster on the natural gas system that impacts, you know, resources here, those kind of extreme events. It's really looking at if everything works perfectly and normally, this is what we can expect.

And so we look at these numbers and, you know, like I said, we don't necessarily -- aren't trying to necessarily pick just the lowest number because that may have additional risks that maybe aren't captured in that number. So we are looking at that and then the bill impact analysis and then taking all of that into context with what are the execution risks and how much of these resources do we have to build and what is the likelihood that we will regret building or not building this resource in the future.

And then we look at, you know, how is it implementing the law? Is it violating CO2? Is it a reasonable delay? Are these reasonable actions supporting this plan? And so we kind of try to take all of that into account when we are making the analysis.

But it's -- it's a very complicated calculation for the PBR and the bill impact. I will say that. And -- but it's a lot that goes into it. But again, as I think we talked about this in the 2022 growth plan, it's not everything, right. There's a lot of the costs that are not included in that PBR. Everything distribution-level is not.

And you all know from the multi-year rate plans that we went through last year that distribution is a significant component of their -- Duke Energy's annual spend. So if anything, these bill impacts are -- are holistically an underestimate.

COMMISSIONER HUGHES: Thank you for that. And you anticipated and answered a lot of my concerns as you often do -- often do. Just -- just a couple clarifications and follow-ups. The -- the bill impact -- you talked about the revenue requirements. You know, the bill impact is just converting the revenue requirements to -- to household bills so you're taking into consideration populations. Is that how you get to there?

MR. THOMAS: Sort of, yes. It's -- essentially, it looks at the revenue requirements projected and kind of compares them to what the revenue requirement is today and it kind of looks at how much is that revenue requirement changing and then it applies that percentage change in each year to the bill.

So it's not like a full cost of the service study. It's not a full rate case. There's a lot of, you know, nuance that's lost there. But it essentially tries to mimic the system and the allocation factors and then allocate those costs over the -- the bill so it's -- call it a -- reframe it as a residential bill. It's kind of a retail bill. It's just showing the changes in the retail revenue requirement and applying that to today's residential bills as an example.

COMMISSIONER HUGHES: Okay. And from an economic standpoint, the present value initially is the present value, so 2023 --

MR. THOMAS: Mm-hmm. Yes.

COMMISSIONER HUGHES: -- dollars. When you're looking at all the bill impact charts, what dollars should I consider those in? Are those 2023 dollars or are those -- do they have inflation baked in?

MR. THOMAS: I believe they have inflation baked in. I can check with you or

Witness Williamson knows for sure. But I believe that those would -- there's inflation reflected in there. And I can clarify for you or --

COMMISSIONER HUGHES: Just -- just moving forward from an economic standpoint, it's really good to kind of --

MR. THOMAS: Yeah.

COMMISSIONER HUGHES: -- that. And the last thing with -- we have so many different scenarios and I don't -- you know, I don't envy your job or anyone's job doing the modeling here. There's a lot of different running scenarios for -- it seems like for some of the other models. Is there running scenarios and sensitivity analysis on the actual cost calculations? So, you know, you mentioned five or six things that we don't know -- you know, cost of capital, inflation, discount rate -- will there be modeling of what the relative cost breakdown of these portfolios looks like if the economic future is very different or is -- I just get the impression that most of the molding is on the technical side and not on the the economic side; is that correct?

MR. THOMAS: I would say -- if you want

to --

MR. METZ: I would say it would be a fair characterization that we didn't perform advanced analytics and modeling exercises to get a degree of uncertainty associated with the bill impact analysis that we try to make one set of distinct assumptions there and look at the changes between portfolios. Mr. Thomas?

COMMISSIONER HUGHES: Okay.

MR. THOMAS: Yeah. I think that -- that's accurate. I think, you know, what happens if we -- you know, if the question you're trying to answer is what happens if we lock in this expansion plan and costs go up by 20 percent or down by 10 or up by 50? We did not complete that analysis.

It would be something that could be done but it is kind of a -- you know, we wanted to look at -- that kind of post-factor analysis and that's really looking at what happens if those costs go up but we were already locked in. And I think we were really kind of looking at some of our sensitivities. How do we get there and what decisions should we try to make today that can be adjusted in the future but still result in time building as least cost?

But point taken. I think, you know, some of that post-talk analysis about cost and what that does to ratepayers' bills could be helpful in illustrating the risk of some of these portfolios.

COMMISSIONER HUGHES: You know, I really appreciate this. I don't want to go into all the details and get into it. There's plenty of time for that. But framing this, you've been very helpful just understanding the -- the targets. So thank you, extremely much.

COMMISSIONER KEMERAIT: That's the end of the questions. Thank you, very much. And you may be excused. We appreciate your presentation.

And we will move on to the Attorney General's Office next.

MR. MOORE: Good morning. The Attorney General's Office calls Ed Burgess to the stand.

MR. BURGESS: Okay. Can you all -- can you hear me?

COMMISSIONER KEMERAIT: Yes.

MR. BURGESS: Great. All right.

Should I begin my presentation then?

COMMISSIONER KEMERAIT: Yes, please begin.

MR. BURGESS: Okay. Good morning, Commissioners. My name is Ed Burgess and my background is in power system planning and renewable energy where I've assisted a wide range of public and private sector clients for over twelve years. I've provided testimony for a number of State Commissions on a range of topics and helped launch Utility of the Future Center at Arizona State University where I received degrees in engineering and multiple graduate degrees.

For about eight years, I was with strategy and consulting and I've now founded -- I'm a founding partner with the new firm Current Energy Group. I'm glad to be here today to provide this presentation on behalf of the Attorney General's Office.

Next slide, please. This provides a brief overview of the topics covered in my testimony on behalf of the Attorney General and a summary of our recommendations. The topic areas on the left include the interim target permission directions, coal retirements, renewable additions, natural gas additions, load forecasting, and customer load reduction programs and transmission planning.

Just to briefly cover a few of these, we recommended an interim target no later than 2032 to satisfy the statutory guidelines while recognizing the challenges from new load growth. And we indicate that in several of these other topics areas, we've not only, I think, offered a critique of some of Duke's analysis in terms of what they may have missed or not included, but presented those as an opportunity for some sort of constructive solutions going forward and how to -- how to better meet that target.

And so I won't have time to go through all of those today in the 15 minutes, so I wanted to focus mainly on one of the target areas which is coal retirements. But I just wanted to flag that we do have these -- what I think are some sort of constructive forward-looking approaches that could be applied in each of the topic areas covered in my testimony.

And so, with that, I think I'll go

forward to the next slide, which is that -- you know, before I get to the sort four strategies to assist with coal retirement, I wanted to just provide a little bit of a context of some of the concerns and preface this by saying a central theme, you know, sort of the concern laid out in my testimony is that we're now entering this critical path time period for both coal retirements and clean energy additions, both of which are necessary to meet the 75 percent interim target within the statutory guidelines.

And, you know, one of the concerns that I raise is with -- we are seeing in the beginning of this patterns of actions or really, you know, inactions on Duke's part over the the last year and a half that may have made that critical path much more difficult to meet and maybe contributing to the company's proposal to delay the interim target by five years.

And I'll use the example of the Mayo Plant. It's just one example. I don't want to overstate, you know, the importance of this. But I think it's indicative -- since this plan is kind of earlier on the timeline. And basically what we saw is, you know, back in -- way back in early 2022, Duke's initial analysis and the accompanist model showed that the optimal retirement date for the Mayo Plant was 2026. They, in their filing, ultimately selected 2029 as the SD retirement date for that plant and, you know, cited issues like need for replacement generation, transmission upgrades as part of the reason for the that.

And so the Commission did order in its final Order in the last cycle to -- for the Duke to take appropriate steps to optimally retire its coal plant on a schedule commensurate with that carbon plan filing. And so, you know, we -- I think we are operating under the assumption that that 2029 date would hold for the Mayo Plant.

We then saw in -- in, you know, the most recent general rate case for the EP that Duke had proposed no new transmission investments for enabling any coal retirements, including the Mayo Plant, and no replacement generation resources for the Mayo Plant either.

And so now, we have come to this carbon plan and we see that the Mayo Plant's retirement date has been delayed yet again until 2031, which doesn't seem consistent with the Commission Order. And again, kind of kicking the can down the road and no action is taken to sort of support the 2029 date that we initially thought was going to be held.

So, you know, I think that -- well, we can go to the next slide. You know, one thing I wanted to also address was this potential, I think, preconception that coal is serving as a base load resource and that we needed to address some of these large loads that are being added. And the fact is that Duke's own modeling shows that, you know, many of these resources are expected to operate relatively frequently more into a peaking resource.

Mayo, for example, has, you know, projected capacity factors in the kind of 4 percent to 11 percent range in 2028, so even after some of these new large loads are added. And that makes, you know, plants like this really ideal for replacement with certain types of peaking resources like batteries that can still support system reliability. They have highly-effective load-carrying contributions.

And, you know, so my testimony, I think, offers, you know, kind of this critique of, you know, maybe what could of -- could have been done at a plant like Mayo but then lays out, you know, I think some recommendations going forward about how we can apply, you know, some of these solutions to maintain, you know, this schedule that's needed to -- for timely retirements.

So next slide. And I want to just sort of remind folks a little bit too about, you know, why does this matter? Why are timely retirements important? It's important to know that, you know, with the coal plants, you know, there's significant costs, not just the fuel but ongoing, you know, capital investments at these plants, you know, rising O&M costs as they get older. And those can be quite significant.

You know, in fact, looking over the planning horizons, fossil resources grow to be one of the largest, you know, components of the revenue requirements in Duke's modeling. And so, you know, some of that investment may be, you know -- could be put towards the newer, clean resources instead.

Additionally, there's, you know, new IRA funding opportunities such as the EIR that Public Staff mentioned. And that's sort of a time-limited opportunity. Some commitments have to be made in this carbon planning cycle and won't be, you know, sort of an option in the next carbon planning cycle.

And so those need to be seriously looked at to see, you know, in some of my analysis, you know, those could reduce replacement capacity costs, the capital costs, you know, some on the order of maybe 20 to 30 percent, so that's going to be a big savings opportunity.

We, of course, heard about the new EPA rules requiring some of these retirements to take place perhaps by 2032, so now is the time to sort of start doing some of those in order to avoid a serious time crunch towards the end of that deadline.

And then finally, the critical path for meeting the 70 percent carbon reduction, you know, it would become much more difficult if we kind of wait until the last minute and start to think about, you know, retiring a lot of generation, you know, right at the -- at the end of that.

And I think it goes without saying too that, you know, continuing some of these coal resources will extend the -- the public health impacts and the emissions that are associated with those.

Next slide, please. Oh, I think we skipped -- if could we go back one? Yeah. There we go. So some of the strategies that, you know, I want to cover, there's four listed here and just in -- in the interest of time, I'll just jump right into the first one, which is more onsite battery replacement, if you want to go to the next slide.

And so one of the strategies that we're recommending here is to consider more battery replacement options at these plants. Dukes's modeling, you know, only assumes that about a little over 4,000 megawatts of the batteries on the total system could be added, you know, versus about 25,000 megawatts of -- of natural gas.

And so, you know, I think my view is that this is an inappropriate assumption for a couple reasons. First, you know, some of the supply chain issues Duke cites, I don't think will persist, you know, through the end of the decade. And then also the fact that there is surplus transmission available at these sites that could help to speed up the interconnection process and could be taken advantage of to get some of these resources online more quickly.

As I mentioned, batteries, according to Duke's analysis, have a high reliability value. In some cases, in the near term, it's a hundred percent EOCC and, you know, sort of going down a little bit over time from there but still very valuable from a reliability perspective. And also, you know, we saw that Duke's modeling did not fully capture some of the IRAs that it looks like the EIRs and also the full amount of the energy communities going to credit.

Next slide, please. Next strategy would be to look more closely at offsite replacement generation in conjunction with any needed transmission upgrades. Duke's said that, you know, some of these retirements will require transmission upgrades if they don't have replacement generation.

And so taking that assumption, the next logical step, in my view, would be to look at, well, what is -- you know, could we do replacement generation somewhere else in the system and still do those transmission upgrades? But that wasn't really studied by Duke. There were some conceptual projects that they mentioned but they didn't actually do any cost analysis on whether those could be feasible in conjunction with the onsite replacement.

And so, you know, as a result, we have a proposal before us that didn't really take into account, you know, some of these more kind of competitive solicitation opportunities. Perhaps there's more, you know, out there beyond just this sort of generation that Duke has proposed at its own sites and we could look into those other options.

Go ahead to the next slide. Another strategy to -- to emphasize is -- is looking at more staggered unit retirements. Duke's modeling basically assumes that, you know, some of these unit retirements would be forced to happen in -- in tandem with each other so you have extremely large amounts of capacity being retired simultaneously, you know, sometimes, you know, several thousand megawatts at a time rather than, you know, thinking about a more staggered approach where you could have one unit retire one year and then another maybe two years later.

And that's pretty common from what I've seen in other utilities and the way they evaluate these retirements rather than locking together, you know, these retirements and that, you know, may prevent -- present more of a blind path or a way to sort of bring online more gradually replacement resources and -- and have some advantages through that.

Next slide, please. Finally, I think, you know, it's warranted to take a closer look at some of the gas conversion options, particularly Belews Creek. That was one of the requirements in the last Carbon Plan Orders to study that Duke did study a sensitivity of Belews Creek in its initial P1 portfolio, but I think it was really, you know, in my view, insufficient to sort of take -- take seriously that, you know, they're -- the fact is that, you know, there's some advantages to this kind of conversion option, can keep online some generation capacity, you know, for sort of an interim period while we get other things online and the capital costs of doing that are very low relative to some of the new capacity options like the new combined cycle, for example.

So Duke's analysis was limited to this one variant and it also had some assumptions in there that, in my view, are a little questionable. For example, including firm transportation capacity for gas all the way through 2045, when really, you know, this was meant to be sort of an interim bridge solution that didn't, you know, wouldn't maintain the plant, you know, nearly at that long. And so I think taking a closer look at those cost assumptions and -- and really taking this, you know, I think, as a serious option.

And then how are we doing on time?

COMMISSIONER KEMERAIT: You have two more minutes.

MR. BURGESS: Okay. Perfect. Final point on this slide. The other thing that this scenario did not include was any deferral of CC capacity. There was some minor deferrals of CT capacity, but, you know, the real, I think, larger cost savings would be come -- come from a CC deferral.

Okay. We'll go to the next slide, please. So just to kind of wrap up in the last minute or two here, some of the key takeaways I just wanted to leave folks with were that, you know, recent inactions on some of these retirements -- Mayo is one example of that -- you know, is, you know, indicative to me that, you know, there may be some more kind of systematic delays with some of these retirements and that may not be in line with what the Commission had directed.

You know, these delays have created a situation where it's going to be a lot more challenging and costly to meet the 2030 target for the interim target. And so, you know, if there's -- I think it's very important, you know, for some of these actions to be taken in the next stretch here. You know, we're really, as I mentioned, kind of in this critical path if we're going meet the interim target consistent with the statutory guidelines.

So, you know, going forward, I think, you know, some of the strategies that I outlined, the four strategies for coal retirement, you know, will be important for -- for doing that while maintaining reliability. But in addition to that, you know, this should be -- you know, I focused on coal today but there's a whole longer series of recommendations in my testimony that should be pursued in concert with that to add, you know, the clean generation to the system and to, you know, have near-term additions of renewables, battery storage, improving, you know, transmission in -- in many ways that I think -- I feel the Public Staff had mentioned earlier too. And then also, focusing much more on customer-sited resources as we're entering this period of higher load growth. So all of the those are part of the package.

And thank you for your attention and I'm happy to take questions.

COMMISSIONER KEMERAIT: Thank you for your -- for your presentation. It was very helpful. Let me check with the Commissioners to see if they have any clarifying questions.

(No response.)

COMMISSIONER KEMERAIT: Seeing none, thank you, and you may step down.

MR. BURGESS: Okay. Thank you.

COMMISSIONER KEMERAIT: CIGFUR, I believe, is next.

MS. CRESS: Thank you. CIGFUR II and III -- excuse me -- calls Brian C. Collins.

COMMISSIONER KEMERAIT: Good morning, Mr. Collins. You may proceed when you're ready.

MR. COLLINS: Good morning. Thank you. Yes, good morning, Commissioners. Thank you again for allowing us to the opportunity to present a summary of our testimony this morning.

MS. CRESS: Mr. Collins, if you could please pull the microphone a little bit closer to you. Thank you.

MR. COLLINS: Okay. Thank you. The purpose of our presentation today is to present a summary of our findings and recommendations.

Duke's purported Pathway 3 to the CPRP updated in the supplemental analysis filed on January 31, 2024 results in the retirement of approximately 8,400 megawatts of coal-fire generation on Duke's system by 2035. Because of the size of the Duke system and scale of the resources necessary to replace coal-fire generation, this level of generation retirement and its timing raises legitimate concerns regarding customer impacts, both in terms of reliability and rates.

As explicitly stated both in House Bill 951 and in the Commission's Order adopting its Initial Carbon Plan, reliability is paramount. The importance of a reliable grid was particularly demonstrated by the events of Winter Storm Elliot in December 2022. This proceeding --

MS. CRESS: Mr. Collins, do you want to change the slide?

MR. COLLINS: Oh, sorry. Yes.

Next slide, please. In this proceeding, Duke specifically requests the Commission affirm its modeling as reasonable and requests approval of certain near-term action planning items as reasonable and necessary to reliably serve under growth -- under the changing energy landscape in North Carolina.

With respect to its near-term action plan items, Duke is requesting Commission pre-approval to incur specific project development costs for certain long-lead-time resources, including onshore wind, pumped hydro storage and advanced nuclear.

Next slide, please. The specific resources incremental to Duke's August 2023 CPIRP filing that Duke included in the supplemental analysis amount to over 7 gigawatts and now includes offshore wind as well as additional natural gas-fired capacity, solar and battery storage.

Duke claims that the primary reason for the January 31, 2024 supplemental analysis filing was due to what Duke considers expected extraordinary load both on its system retiring incremental resources that it claims should now be included in the CPIRP as compared to the August 2023 filing.

Next slide, please. According to Duke, the forecasted 2038 winter peak has increased from 35.3 gigawatts in the August 2023 filing to 37.6 gigawatts in the January 2024 filing, an increase of 2.1 gigawatts or approximately 5 percent. The annual energy forecast has increased by 24 terawatt hours or approximately 12 percent. This is a significant increase in expected load for both DEC and DEP's respective operations in North Carolina.

The total cumulative capital spend for the CPIRP in Duke's August 2023 filing was $92 billion by 2038. In the January 2024 update, Duke now estimates its total cumulative capital spend by 2038 to be $128 billion. This is a significant increase of approximately $36 billion or approximately 39 percent in the span of less than six months.

Next slide, please. In the August 2023 CPIRP filing, Duke estimated customer bill impacts growing at a compound annual growth rate of approximately 2.2 percent for DEP and 2.9 percent for DEC for the period 2024 to 2038. In its January 2024 CPIRP supplemental analysis filing and update, Duke now estimates customer impacts growing at a compound annual growth rate of approximately 3.4 percent for DEP and 3.7 percent for DEC for the period of 2024 to 2038.

These are significant annual compounding increases. As a result, Duke's revised forecasted compounded annual growth rates result in cumulative customer bill increases of approximately of 60 percent for DEP and 66 percent for DEC by 2038 as compared to the 2024 rate levels. These are significant bill impacts for customers and do not even include all expected costs that Duke will incur for executing its carbon plan, nor do they include capital investments that are unrelated to carbon plan implementation. As a result, these are not all-in cost estimates. These already concerning rate impact estimates are conservative.

Next slide, please. For perspective, the current estimated customer bill impacts by 2038 versus current rates in 2024 would amount to an approximate $1.5 million per month bill increase for a typical 50 megawatt industrial customer and taking transmission service with a 90 percent load factor. Considering that these are estimates and that they are understated because they do not reflect all costs necessary to implement the carbon plan, nor costs related to the implementation of the carbon plan, expected level of future bill increases for customers are staggering and should give the Commission great pause. The magnitude of expected bill increases and the threat to the committed business of industrial customers in Duke's service territories, not to mention the threat to Duke's residential and commercial customers.

Along these lines, it should also be noted -- next slide, please -- that Duke's residential customers shall see approximate increases of $87 per month by 2038 based on Duke's estimated compounded annual growth rates in the January 2024 supplemental filing. Again, there are extraordinary increases and conservative estimates and should cause the Commission to question whether Duke's as final CPIRP constitutes reasonable steps as contemplated by the NCGA in House Bill 951.

The actual customer impacts experienced by 2038 will likely be much higher because the CPIRP includes only estimated generation transmission costs do not reflect the complete actual transition investment costs necessary to implement the company's CPIRP. Furthermore, these impacts do not account for the non-CPIRP investments in the company's generation, transmission and distribution systems.

Next slide, please. Regarding reliability, the present law requires that reliability should be maintained or improved because of the unprecedented level of intermittent resources planned to the Duke system to replace historically-reliable coal-fire generation. The Commission should be flexible and give the Company as much time as is required for meeting its emissions reductions. We believe more time is needed for implementing the CPIRP due to the uncertainty in load growth, resource costs, supply constraints, and viability of new and unproven resource technologies to enable reliable operations of the Duke system.

Next slide, please. Duke examined other pathways for achieving a 70 percent carbon emissions reductions by 2030. However, there is increased costs and risks to reliably meeting the interim 70 percent target by 2030. As a result, I recommend that the Commission not require Duke to meet the 70 percent emission reduction target by 2030 and instead focus on what steps and timeline are reasonable under the totality of the circumstances while complying with the requirement that reliability must be maintained or improved.

Because of the risks and the uncertainties in implementing the CPIRP, Duke has recognized that its recommended 2035 target for 70 percent emissions reductions via its preferred Pathway 3 could be extended further into the future. The Commission has the discretion to determine optimal timing as well as the appropriate duration and reserve mix to achieve the least cost path to compliance. Importantly, it must take only all reasonable steps to implement the carbon plan.

Next slide, please. On top of the uncertainty regarding assumptions in the CPIRP, one concern is the the unknown impacts if joint capacity planning had been performed by Duke on a combined basis for both DEP and DEC. The lack of joint planning by DEC and DEP is a significant impediment to developing a least-cost plan for emission reductions that can be approved by the Commission. Again, this uncertainty regarding joint planning is troubling. And again, the impact is unknown.

As a result of the discretion afforded the Commission and the requirement for the Commission to take only those reasonable steps in implementing the CPIRP, I recommend the Commission require Duke to model a scenario in which DEC and DEP are sharing capacity for planning purposes. This recommendation protects ratepayers from the risk of the Companies overspending and overbuilding in the interim before a potential merger is consummated. Per the Companies' expectation, the merger will be effective approximately January 1, 2027.

Next slide, please. Certainly should be reached regarding the merger of DEP and DEC as soon as possible to avoid Duke's progression down a path that could have adverse consequences on customers in terms of both reliability and customer bill impacts. If the optimal resources on a combined basis -- joint planning basis are not selected for replacing coal-fire generation as part of the near-term action plan and/or otherwise. If this this is not possible, the Commission should consider delaying the timeline for achieving the interim emissions reduction targets set forth in House Bill 951.

Next slide, please. I also recommend that the Commission establish rate mitigation measures for customers with respect to CPIRP implementation to protect ratepayers from the unprecedented and extraordinary exposure to rate increases associated with the CPIRP implementation. This is reasonable, important and necessary for customer protection.

Rate mitigation could be, for example, in the form of the rate phase-in over a specified period of time after Duke is granted an increase in rate case recovery costs associated with implementing the carbon plan. The parameters regarding rate mitigation could be developed and implemented due to collaboration with Duke, the Public Staff and customers.

Next slide, please. Though the company is required to file an updated CPIRP every two years, the the current environment is dynamic and in flex with respect to load growth, resource costs and availability, supply constraints and resource technology development, creating uncertainty regarding reliability and bill impacts for the customers. Therefore, I recommend that the Commission require updates from Duke every six months regarding the progress of the CPIRP. This is a reasonable requirement, especially in light of the extraordinary load increase that occurred less than six months after Duke's CPIRP filing in August 2023, as well as the significant rate impacts Duke projects.

Next slide, please. Specifically, I recommend the Company be required to file to the Commission status reports every six months identifying any major developments in the process. These reports should include an update to the approved portfolios or portfolio as the case may be, the present value of the revenue requirement, total capital spend and estimated customer rate impacts. More frequent updates are needed on the process beyond just the two-year updated formal filing. This would add another layer of customer protection and complement the biennial filing, warn the Commission if the circumstances have changed regarding the preferred CPIRP and help the Commission and the Companies check and adjust sooner rather than later.

Next slide, please. I also recommend that the Company include estimated rate impacts on a class-by-class basis to the proposed six-month reports for all expected investment on its system, including not just the CPIRP-related investments, but also the non-CPIRP investments. This would give the Commission a holistic view of the expected customer rate impacts on the horizon.

That concludes my presentation. Thank you, very much, for your time. If you have any questions, I would be happy to answer those.

COMMISSIONER KEMERAIT: Thank you, Mr. Collins, for your presentation. Let me check with the Commissioners to see if they have any clarifying questions.

(No response.)

COMMISSIONER KEMERAIT: Okay. Seeing none, thank you, and you may be excused.

MR. COLLINS: Thank you, very much.

COMMISSIONER KEMERAIT: I believe that NCSEA is next.

MR. SOMELOFSKE: Thank you, Presiding Commissioner Kemerait. The North Carolina

Sustainable Energy Association calls Dr. John O'Brien to the stand.

And Presiding Commissioner Kemerait, Dr. O'Brien has elected to forego slides. But we do have a hard copy of the outline that was pre-filed Wednesday for the Procedural Order. If the Commission would like a hard copy, I can pass that around now.

COMMISSIONER KEMERAIT: Do you have hard copies available?

MR. SOMELOFSKE: Yes.

COMMISSIONER KEMERAIT: Okay. That would be great. Thank you.

DR. O'BRIEN: Good morning, and thank you for the opportunity to address you. We were retained -- I'm with the Vista Consulting Group. We were retained to perform a study for NCSEA to do an apples-to-apples comparison of wind and nuclear. We --

COMMISSIONER KEMERAIT: Dr. O'Brien, can you move the microphone a little closer to you so we can hear you better. Thank you.

DR. O'BRIEN: My background is I was a scientist for the Department of Energy studying nuclear energy. And after that, I did spend time as a Commissioner on the floor of the Energy Commission, which was a Legislative Commission, and chair of the Climate Change Subcommittee of that Commission.

As I mentioned, we were retained to look at the aspects of both nuclear and wind side by side in an apples-to-apples manner. The discussion I'll have today is really more qualitative than the discussions that I've heard so far. Because I believe that there are issues going forward of adequacy and reliability that need to be factored into the decision about offshore wind.

Mr. Moore, who authored the piece on the nuclear side, could not be here today. He is a veteran of the nuclear industry and still a strong participant in it. I was teaching a course as a public -- I'm a professor of public administration, and I was teaching a course on public economy when I did this study. And one thing I was very impressed by is the economy of North Carolina. I believe that it is well-poised to become probably the fastest-growing economy as

-- on a state level in the United States over the next decade.

And my concern -- and I have a list of things that I could go on about the economy here, but the one that is probably most important with regards to the discussion today is the manufacturing sector in this state. It is robust. It is large. It is poised to grow. And both nuclear and wind will contribute strongly to the growth of those sectors in this economy.

But I'm not going to go through all of that. What I'm going to do is I'm going to go forward and just point out this is not a normal IRP at all. It is very abnormal. There are factors that have come into this that are unusually different than the ones that are normally confronted by any Utility Commission trying to determine a forward mix of generation and other assets.

You have to back down on the carbon emissions and you're introducing new technologies and new business models. Completely different. The two business models are also second mover models. In other words, first of a kind is not going to happen in nuclear, is not going to happen in wind.

And so why do you do first of -- why do you do second of a kind or second mover? It's to get information from the first movers. And that is an important aspect of this that I believe has to be taken seriously with regard to the allocation of resources for determining the mix.

New nuclear is something that we are in favor of. We think that the new nuclear aspect -- and I have a study here. It's quite a comprehensive study comparing the two of them. And it's not a modeling exercise. It is an actuarial discussion based on facts of the two different technologies, side by side, how they compare. And I will cut to the chase now and just tell you that the -- there is no advantage to nuclear in terms of starting that first.

But it seems as if what has happened is it's go nuclear. You have allocated resources to it. It is the early site preparations going on. Well, with wind, it's more like wait until we see if we need it. And the problem with that is that nuclear has uncertainty to it, especially the new nuclear. Even the old nuclear has uncertainty to it.

And I don't want you to get me wrong. I am not anti-nuclear. I think that that must be in the mix, that it must be pursued. The problem is, as I mentioned, the economy here over the next decade is going to grow very rapidly, very -- and many, many benefits will accrue to the citizens of the state because of that, because when you grow GDP, everybody gets a slice. The problem is that if there is a hiccup with the new nuclear and you haven't taken the time to look very closely at the wind option, then that option may not end up being available.

So the conclusion of our report, as I mentioned, is that there is nothing that says that new nuclear should be deployed before wind; that, in fact, the early development costs for winds are very small. The hundreds of millions of dollars that have been put on the table with regard to nuclear is more than you could spend on early development for new wind. You've got two developers here who have already gone through and worked on it and invested significant funds.

So the last part of this is there was a proposal for an AR -- ARMI. I want to point out that everything in here is an RFI if you look at classic public administration. That is all what we are doing. And the idea of getting more information outside of the realm of actual negotiations between the developers and the Companies is not going to work.

The way this happens is these two developers, Avangrid and Total, are negotiating right now with other states and other utilities and they're coming to conclusions. There are wind farms being built -- there are wind farms operating in the northeast sending -- offshore wind farms sending power into the the continent. Those are the lessons learned. That's why you have a second mover strategy with regard to nuclear is to let somebody else be the pioneer and take the arrows. Somebody else is taking those arrows. They're the developers that are here.

It is very important, in my opinion, that direct negotiations occur, not more information gathering; that there should be two negotiations. And this is my recommendation --

it's our recommendation. Number one, go forward with nuclear. Do that. But the second part of the recommendation is set up two separate negotiations between each of the developers and the Companies.

But have those negotiations be real negotiations where agreements can be reached, where you can see the outcome, where real costs come out of it. Not a study that tells you what the cost might be. We did that. It's right in here. We have cost data in here. It's not a modeling exercise. But we can say what things cost, whether there are vessels to do it. All of the other things are in here.

So that is really what we are recommending is that within the context of the ARFI, if that's what it is that you end up calling that procedure, that you also have a paper record reporting in the judicial world. You have joint status conferences and joint status letters and all kinds of things of that nature. It's not expensive. It's a no-risk strategy.

But the risk that exists if that is not going to occur is that this economy will -- as it will grow. You have big tech coming in. You have an incredible economy in this state, speaking as an economist, that it will be growing and nuclear will hiccup, which it has in the past.

We also, by the way, predict -- and the data for it are in here -- that new nuclear will not be available until 2039 as opposed to what's in the plan. And the reasons for that are in the report. So I just implore you to consider the idea of initiating meaningful constructive negotiations between the companies and the developers. Thank you.

COMMISSIONER KEMERAIT: Thank you, Dr. O'Brien. I just have one clarifying question for you about -- you're recommending, as you call it, meaningful negotiations about offshore wind. What is the difference in time frame between what you could expect from those types of negotiations versus an ARFI?

DR. O'BRIEN: Well, the -- to get an interim, let's say, a penultimate report by the end of this year, you could start and it could begin. And I believe that within the next time frame that you are considering this overall plan, that you would have real data, real agreements. Right now, it's not even clear whether it's going to be owned and operated by the companies or whether it's going to be an off-take agreement with regulatory-like conditions in it to allow for cost recovery.

So I think it's going to take time to put that together. But what is essential would be those negotiations sitting across the table from each other. The company -- the developers already know the answers. They're constructing those answers today in other venues.

COMMISSIONER KEMERAIT: Thank you.

DR. O'BRIEN: So I can't really say how long it would take. But what I can say not -- in my opinion, not going down that road means that offshore wind may not end up being able to replace the capacity for generation if the new nuclear option, for some reason, as it has in the past many times, hit a hard -- hit a block at some point.

COMMISSIONER KEMERAIT: Thank you for that clarification, Dr. O'Brian. Let me see check and see if there's any additional clarifying questions.

(No response.)

COMMISSIONER KEMERAIT: There are not, so thank you for your presentation and you may step down.

DR. O'BRIEN: Thank you, so much.

COMMISSIONER KEMERAIT: Looks like it is SACE that is next up.

MR. NEIL: Thank you, Presiding Commissioner Kemerait. We would call Mr. Goggin and Mr. Duncan.

COMMISSIONER KEMERAIT: Good morning. You may proceed as soon as you're ready.

MR. DUNCAN: Thank you. Good morning, Commissioners. Thank you, very much, for having us today. My name is Jake Duncan. I'm the southeast regulatory director for Vote Solar. With me today is Michael Goggin with GridStrategies, LLC. In the interest of efficiency today, I'll speak for a while and then pass it to Mr. Goggin at the very end.

Next slide, please. So we -- we both presented testimony on behalf of SACE et al., and jointly with North Carolina Sustainable Energy

Association.

Next slide, please. I'll describe the overview of the testimony that SACE et al., put forward, dive a little bit deeper into my testimony and then again, pass it off to Mr. Goggin at the end.

So SACE et al. put forward four pieces of testimony designed to address the holistic cycle of the -- of the resource planning costs. It started with Witness Wilson to address the large new loads, the load forecasts and the resource adequacy study. Witness Roumbani addressed the analysis of Duke's modeling. She got into fine detail a lot of the modeling decisions and the analysis that Duke put forward and then -- and also assessed the resource and portfolio selection that the company put forward.

Mr. Goggin, to my left, addressed transmission plan, interconnection solutions. And myself, I submitted testimony on maximizing and distributing energy resources to fill in the gaps of the transmission scale resources that we need help with.

Next slide, please. Unfortunately

Witness Wilson and Roumbani can't be here with us today, so I'll briefly summarize their testimony. Again, Witness Wilson addressed the Companies' load forecasts and resource adequacy studies. His core recommendations were to address the large new loads by taking -- essentially taking them out, creating a different class for any large new loads, 20 megawatts or greater, and then creating several different pathways to address these new loads to -- to add a level of certainty to the load, whether or not it's going to self-generate, whether or not it will take a longer -- a long-term contract or if it will be more uncertain and then address those accordingly.

Witness Wilson further recommended the Commission engage professional forecasters to create a more -- I'm sorry -- that the Company engage professional forecasters to develop a more comprehensive load forecast, a scenario analysis, and that the Company further study the relationship between extreme winter weather and -- and load to gain better insight into winter resource adequacies.

Witness Roumbani, again, evaluated

Duke's analysis for both pathways. Her core recommendations were to -- that the Commission should not approve Duke's recommended P3 fall supplemental portfolio -- portfolio or the near-term action plan. She recommended that the Commission hold in abeyance any decision regarding Duke's proposed gas build-out until there can be more certainty around the economic utilization and the response to the EPA regulations.

She recommended that the Commission require that any further CPCN for gas include a required clean portfolio alternate analysis and that the -- Duke explore earlier coal retirements and that the Commission should approve wind and solar additions consistent with P1 base core.

And Witness Goggin will -- will get into more detail about how we can interconnect those -- those level of resources consistent with the P1 base core.

Next slide, please.

COMMISSIONER KEMERAIT: I do have one clarifying question from Witness Wilson, the last point -- and you may not know the answers to this since it's coming from a different witness.

But it states that Duke should study the relationship between extreme winter whether and load. Is her testimony that Duke did not do that in its filings or that they're looking for further information? If you know.

MR. DUNCAN: I -- I cannot answer that question.

COMMISSIONER KEMERAIT: We can explore it further during the evidentiary hearing. Thank you.

MR. DUNCAN: Next slide, please. I'll take a few minutes to dive into my testimony. Again, I evaluated the integration of distributive energy resources into the planning process with origin in four key areas: Planning and storage, electric vehicle maintenance charging, virtual power plants and bio-lead distribution resource planning.

Next slide, please. So for behind-the-meter storage, at the high level, the companies did not integrate behind-the-meter storage into its resource planning at all. This is the type of fact that behind-the-meter storage carrying rate with solar grew from 1 percent in

2019 to 20 -- sorry -- 10 percent in 2022, and it is expected to keep growing due to national trends and the -- the change of the solar choice tariffs.

So in order to assess the kind of the scale of this customer resource that the company is not paying for, yet is shaping load and likely reducing peak, I performed kind of a high-level analysis that took the Companies' own behind-the-meter solar forecast and applied some assumptions around the level at which customers will pair solar storages with that based on data from the Lawrence Berkeley National Lab and Solar Energy Industry Association.

They found that by 2038, there may be around 469 megawatts of behind-the-meter storage on the system and around a gigawatt by 2050. Again, these are customer-owned resources that the customers are using to shape their own load and potentially reduce peak that is not currently appropriated into the forecast.

Next slide, please. My recommendation regarding behind-the-meter storage are: One, to require the company to revise its proposed plan to incorporate a behind-the-meter storage forecast for the minimum required forecast incorporated in the future plans. This forecast should be structured to delineate between what I'm calling naturally-occurring storage, which customers would adopt of their own volition with no outside financing or incentives or core payments of the Company and any storage that might receive a payment from the Company for grid services that the storage offers.

I then also recommend that Duke be required to evaluate how incorporating these behind-the-meter storage resources may change the modeled selection of the combustion turbines.

Next slide, please. Moving on to electric --

COMMISSIONER KEMERAIT: Before we move on, I have a clarifying question about the behind-the-meter storage. Did Duke not include any behind-the-meter storage in its forecast or was it just minimal? Can you elaborate on whether they included it at all.

MR. DUNCAN: Subject to checks in discovery, the Company stated they did not incorporate any behind-the-meter storage in their load forecast.

COMMISSIONER KEMERAIT: Thank you. And Commissioner Duffley.

COMMISSIONER DUFFLEY: And the 10 percent growth, what's the split between residential and nonresidential?

MR. DUNCAN: I am not sure of that. The answer to that, that was taken from the company's testimony in the CPIRP. They stated -- they just stated that occurred from 1 percent to 10 percent in those years.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. DUNCAN: Next slide, please. Moving on to the electric vehicle maintenance charging. The company, again, did not incorporate EV maintenance charging into its load forecast so it asymmetrically treated EV load by including the entirety of the projected yet-to-be-realized EV load, but did not incorporate the entirety of the yet-to-be-realized EV maintenance charging or other load management protocols.

So again, to develop a kind of a potential analysis, I applied a few assumptions to the Companies' EV peak load forecast. I assumed that -- I took the assumption from The Brattle Group's virtual power plant report that 40 percent of the EV management maintenance charging will participate in -- I'm sorry -- 40 percent of EV load will participate in maintenance charging by the 2030s.

In the findings from a South Carolina Duke-managed charging pilot that saw 76 percent reduction in peak load and this produced a 2038 winter peaking resource of 251 megawatts and a summer peaking resource of 658 megawatts in 2038. This is reinforced by the fact that in a supplemental modeling, the companies did include a North Carolina time of use rate, which is different, of course, than a maintenance charging program. That also reduced summer and winter peaking by meaningful amounts.

Next slide, please. So to remedy this, I recommend that the Commission determine that the current -- the Companies' load forecast overestimates EV loads and to incorporate EV load management -- I'm sorry -- EV management potential into current CPIRP, or at very minimum, future

CPIRPs.

Next slide, please. Moving on to the virtual power plants. Again, the company did not model virtual power plants as a resource in its IRP. VPP is different from other DERs in two regards. One is their aggregation of multiple DERs generally put together. And two, that they're designed specifically for -- to deliver a grid resource.

VPPs are further the only resource that can meet grid needs and lower customer bills because the cost to the company of running the program of -- a big chunk of that cost is payments to individual customers for the value they're producing to the grid. And PowerPair and the recently approved active load management will enable greater VPP growth and knowledge for modeling in the future.

So my recommendations regarding VPPs are that the Commission requires the Company to work with stakeholders to do two main things. One, to incorporate a behind-the-meter solar plus storage program as a supply site resource in the future CPIRP to be based off of the learnings from

PowerPair and this would include CNI customers. So after PowerPair runs for a while, we'll know the cost to the Company and how it performs and what services are delivered. And so that can be submitted to the model a selectable resource and the model could select 20-30 megawatt chunks of PowerPair as a system resource.

And second is to create a portfolio -- several portfolios of a variety of command site management programs together that can holistically act like a -- like a power plant that the Company could submit as a supply site resource in the future modeling. And then finally, I recommend that the Commission salvage a 300 megawatt by 2030 EPPP goal for the Company.

Next slide, please. Finally, distribution resource planning is a -- is a key element to enable the maximum deployment of cost-effective DERs. Distribution resource plans provide deeper analysis, data sharing, clear investment planning and really guide the company's DER programs and investments. I will stress that the Duke's integrated system operations plans or ISOP is not a DRP and I lay out the reasons why in my testimony.

That's reinforced by the image on the left of the screen, which is a map from the Lawrence Berkeley National Lab that lays out states with clear distribution planning requirements. You can see North and South Carolina are not on there.

And so my core recommendations on the next slide are that the Commission should establish distribution resource plan requirements as a part of the future CPIRPs that have specific goals, timely retirements and procedures that I lay out specific recommendations at the starting point in my testimony.

And so, with that, I'll pass it off to Mr. Goggin.

MR. GOGGIN: Thank you. Michael Goggin with GridStrategies and I'm talking about grid issues. I focus mainly on the transmission systems.

I have a number of proposals for recommendations for how Duke can more quickly interconnect new resources, particularly renewables and battery storage. These include expedited interconnection processes using battery storage to help interconnect other resources and also just moving to more proactive multi-value transition planning. That's generally a much more effective way of planning and paying for transmission than using the reactive interconnections queue.

And, you know, Duke is moving in that direction with the multi-values peak transmission process of the the Carolinas Transmission Planning Collaborative. However, I have recommendations for how that process could be strengthened and the Commission could require that the transmission that is being built actually be planned through that process.

I also found that the interconnection costs that Duke has assumed in its economic modeling for wind and solar resources were excessive in some cases and that does buy into the analysis against those resources. More importantly, the limits on the economic modeling of -- the economic deployment of solar and batteries I think does significantly skew the build. It basically limits how much of those low-cost resources the model can select for both using solar and energy needs and the batteries can be a capacity need. And that, I think, underdevelops those solar and storage resources and therefore overdevelops the gas resources to meet those energy and capacity needs instead.

And so I review the rates, which other grid operators have been able to interconnect solar and storage and find it's much higher. And then, as I mentioned, I have a number of solutions for how Duke can expedite the interconnection and move to a much higher rate of interconnection that would, you know, be higher than those proposed limits.

I also -- in the transmission expansion, I talk about the value of expanding transmission ties to neighboring grid operators, both for economic interchange and, you know, accommodating these higher renewable levels, but also for accessing diversity during extreme weather events like Winter Storm Elliot. The reality is that, you know, sometimes, you know, you and a neighbor will be affected by a storm but at least one of your neighbors is likely not going to be as severely impacted and that gives you a really valuable lifeline for those situations.

And then finally, I do review some of the reliability and economic risks associated with gas generation, including looking at -- looking at Winter Storm Elliot and basically explain how, you know, resources like renewables and storage that do not have those fuel price risks I think are, you know, really valuable and helps diversify the portfolio. Thank you.

MR. DUNCAN: That concludes our remarks. Thank you.

COMMISSIONER KEMERAIT: Thank you for your presentation. Let me see if there's any clarifying questions.

(No response.)

COMMISSIONER KEMERAIT: There are not any, so you may step down and we appreciate your presentations. And I believe that the Environmental Defense Fund is next.

MR. SMITH: Yes, Presiding Chair. I have physical copies of the slides as well for easier review if you all would like them. Otherwise, we can just rely on the screens.

COMMISSIONER KEMERAIT: We have the -- the information already.

MR. SMITH: Okay.

COMMISSIONER KEMERAIT: So we don't need anything to be passed out.

MR. SMITH: I'm calling Bill McAleb and Josh Kaplowitz.

COMMISSIONER KEMERAIT: Good afternoon -- I should say good morning still. You may begin your presentations whenever you're ready.

MR. McALEB: I was wondering that before or after?

MR. KAPLOWITZ: Oh. Looks like I'm --

MR. McALEB: Oh.

MR. KAPLOWITZ: My name is Josh Kaplowitz. I am senior counsel with Locke Lord. I have been working in the U.S. offshore wind industry for over twelve years.

My most recent experience was with -- as the vice president for offshore wind at the American Clean Power Association, a role I've played for two years. And then I've spent five years as counsel to the Bureau of Ocean Energy Management and the Department of Interior on offshore wind leasing and permitting. So I bring a national perspective, unbiased by any particular developer or project, and an inside perspective on the federal role for offshore wind.

Next slide. I'm going to build off of Dr. O'Brian's testimony and I have -- so I have five key points that I want to make and I welcome questions along the way.

First point I want to make is that offshore wind is a mature global industry which is rapidly maturing in the United States. As Dr. O'Brien noted, this would make Duke a second mover able to take advantage of the significant experience that has already accrued.

Second, offshore wind provides some unique benefits to ratepayers as compared to other resources, both renewable and conventional.
Three, and perhaps most important, offshore wind needs contractual certainty in order to happen in any state, but particularly in North Carolina.
And there is a bit of a window of time in order to provide that certainty and get offshore wind to fulfill its full potential.

Fourth, I believe that offshore wind,

based on my analysis, I believe offshore wind can deliver as soon as 2031 or 2032 if it is provided with those contractual certainty as soon as possible. And lastly, I implore this Commission to take the broader view and look at how offshore -- how a project pipeline of offshore wind can optimize ratepayer value and provide optionality, not just for the interim goal but also for the zero net carbon goal of 2050.

Next slide.

COMMISSIONER KEMERAIT: And before you go to the next slide --

MR. KAPLOWITZ: Sure.

COMMISSIONER KEMERAIT: -- I have a question about -- you say offshore wind needs contractual certainty soon. Can you explain a little bit more about that and what time period specifically "soon" refers to?

MR. KAPLOWITZ: Absolutely. Well, so contractual certainty means -- what I mean by that is a legal mechanism that allows for project developers to have -- you know, to be able to economically develop their projects and make -- make those investments. I am agnostic as to what that mechanism looks like. There are lots of options. You see just north of us in Virginia, a pretty good model in the regulated utility space but there are lots of different ways to slice that onion.

But the important thing is you need project developers and we've seen this up and down the east coast. You need that certainty in order to pull the trigger on investing, not just in procurements of large components, but also the permitting process, which is incredibly intensive, capital intensive in sort of investing and surveys and the like, so...

COMMISSIONER KEMERAIT: And -- and could you follow up and just tell us what your recommendations about that -- when "soon" is. What do you mean by that and what are you requesting that the Commission consider that contractual certainty?

MR. KAPLOWITZ: So I'm recommending that the the ARFI or the advanced or the -- sorry, the ARFI include a commitment or an Order to get Duke to commit to a contractual mechanism at the end of the ARFI process. So I don't want to put an exact date on it but ideally, it would come as soon as, you know, the end of -- the end of 2025.

By the end of 2025 at the latest, we would want individual projects to have that -- you know, in sufficient capacity to have that contractual certainty. And as I can show you, that will sort of set the first domino and allow for development to happen. And as you've seen with projects up and down the east coast, we have a lot of reference points and once you get that contractual certainty, there is roughly a six-to-seven-year runway between that contractual certainty and when these projects can be not only constructed but up and running and delivering power into the the grid, so...

COMMISSIONER KEMERAIT: Thank you. You can go ahead with your presentation.

MR. KAPLOWITZ: Sure. Yeah. I got a little bit ahead of myself.

I can -- next slide here -- can weave in that response. But -- so talking about offshore wind as it stands now, it is a mature industry and it is rapidly maturing in the United States. The industry is more than 30 years old.

The first offshore wind farm was built in 1991. 75 gigawatts have been deployed in Europe and Asia primarily, but also in the United States by the end of last year. Costs have been declining over time and this is due to several factors including just repetition, you know, muscle memory, supply chain maturity, standardization of processes and increasingly large winter -- and more efficient wind turbine generators.

The U.S. has lagged, but I am proud to say that at this moment, 4.1 gigawatts of offshore wind is under construction in the U.S. today, and 2.6 of those gigawatts is under construction off of Virginia Beach, just to the north of us. We'll talk more about that in a second. The chart here -- I've done a calculation. If, you know, to your point about timing, if we can get certainty, contractual certainty, by the end of next year, developers, I believe, that those first projects can start construction around, you know, as soon as 2030/2031.

Based on my calculations, on that date, you could have as many as 18.7 gigawatts of offshore wind spinning in U.S. waters on the east coast by 2031. I can -- I'm happy to explain more about how I arrived at that calculation. But this is based on existing project proposals and their nameplate capacity. It's based on existing procurements that are either have been awarded or have been announced and scheduled, and based on a reasonable projection of the permitting status of these projects.

Now, the costs, I didn't put this on the slide, but costs have gone up recently due to macroeconomic factors like inflation and rising interest rates. But NREL projects that those costs -- is not a blip, at least something that is going to be overridden by these general trends that we've seen on other continents where costs do decline as the supply chain develops and you get that muscle memory.

Next slide. So offshore wind carries some benefits, some unique benefits that really aren't found in other resources. Offshore wind is good for reliability. It balances onshore solar. You've probably seen these charts before but this is -- you know, the offshore wind blows strongest when there isn't solar energy. So they work well together.

Offshore wind has a really high capacity factor for an intermittent resource -- over 40 percent. And this is because offshore wind blows stronger and more consistently than onshore wind. So it really does add -- add resiliency to the mix, to say nothing of the fuel cost savings. But Dominion, for example, calculated over $3 billion of fuel cost savings over -- just over the first ten years of its 2.6 gigawatt project being -- being operated.

And then there are -- I know this is outside of this Committee's jurisdiction but there are substantial economic developments that Southeastern Wind Coalition found. $3.6 billion -- calculated $3.6 billion in economic benefits to the state just from a 2.8 gigawatt project. That includes ports, manufacturing opportunities and the like.

So how can we bring those benefits to North Carolina? Next slide. So we've talked about this already but the need for contractual certainty is really a prerequisite and this chart really underlines that. If you look at the seven states that have mandatory procurements of offshore wind, those are the states, not coincidentally, where offshore wind has happened or is -- or where projects are either -- have been built, are under construction or are in the advanced stages of planning, whereas states that have goals but not -- sort of not those mandates for contractual certainty, projects tend to -- tend to languish because there isn't that catalyst to -- to investment.

Really good example here is in Virginia, our neighbor to the north, they -- the Virginia Clean Energy Act had a 5.2 gigawatt offshore wind mandate that directly lead to what we see now, which is steel in the water and a project that is on time -- projected to be delivered on time and under budget.

North Carolina has given us the policy direction in HB 951 that it's tech neutral and it's up to this Commission to determine that generation mix and incumbent on this Commission, we hope, to send that signal -- the same signal that -- that Dominion received in Virginia and then was able -- has been able to execute.

Another really important point is, you know, there is that gap, right, between today and contractual certainty at the end of 2025. And I believe that there is an opportunity to get the -- get the ball rolling by providing cost recovery, you know, to developers to make sure that their permitting process can go forward. I had mentioned earlier permitting takes a huge investment in surveys. That investment may not be made until there is cost -- until there is contractual certainty. If -- but we can accelerate that process and do a bridge by having cost recovery to allow those developers to make those -- make those preliminary investments in permitting, which is an extremely lengthy and complicated process.

The ARFI just doesn't quite get there. And we -- I would agree with the Public Staff that it just doesn't provide the certainty that these developers need and that without that certainty, Duke may be -- may get similarly disappointing results as they got in the last -- in the last RFI. And delay here, failure to provide that certainty has some real consequences. Rising costs -- they got to get them to the procurement pipeline, right. The longer you wait, the more expensive components could be. So being able to get into the queue to charter vessels to build these projects, to get in the queue for -- for components is really important and you might miss the benefits of the certain IRA tax credits.

And just lastly, renewable development and offshore wind in particular is a global industry. And if you don't have -- if a company doesn't have the right regulatory environment, they could take their investments elsewhere. And so the developers here are waiting for that right regulatory environment in order to pull the trigger and there's plenty of places where they can invest if -- if the environment doesn't -- doesn't improve.

Next slide. Timing of first delivery, we already talked about this. This is my calculation, the -- the six-to-seven-year window, so I think that the Duke's calculation of 2025 is -- is a couple years later than it needs to be.

Next slide. And finally, I would urge this Commission to not stop at the 2.4 gigawatts that -- that Duke has fortunately, you know, proffered as their goal. A one-shot 2.4 gigawatt goal really kind of, I think, sells North Carolina and its ratepayers and its manufacturing sector short. Having a pipeline of projects will improve the -- the economics of these projects for obvious reasons. If you -- you can create economies of scale. And there is an opportunity here. I mean, the NREL has calculated that the -- just the leases that exist today, which have been subject to substantial work de-conflicting and finding the best places to build offshore wind could generate up to or over 6 gigawatts. So that's a lot more than the 2.4 and I would urge the Commission to consider that, at least taking advantage of and not wasting the generating capacity for existing leases.

But we shouldn't stop there. North Carolina has one of the longest coastlines; certainly a longer coastline than any state to the north. There is a huge opportunity for additional resources, particularly as they're looking towards 2050. So I would urge the Commission to at least order Duke to study the possibility of increased generation beyond the existing leases.

I know that BOEM, the Bureau of Ocean Energy Management, is looking at potentially leasing. They take signals from states. They really follow the states' leads. And so there's an opportunity here for North Carolina to really be a leader but also a second mover. So other states and other projects have made - you know, have learned some lessons and we can take advantage of that. So I look forward to further dialogue and that is my testimony.

COMMISSIONER KEMERAIT: I have one question. Can you go back one slide to the slide entitled, "Timing of First Delivery."

MR. KAPLOWITZ: Sure.

COMMISSIONER KEMERAIT: And I'm interested in the PPAs that you've referenced for Vineyard Wind One and Revolution Wind. Vineyard Wind One talks about a PPA from Massachusetts. And then Revolution Wind, that's PPAs from Connecticut and Rhode Island. Do you have any information about who the parties are to those PPAs?

MR. KAPLOWITZ: That's a good question.

They are -- and some of the subsequent witnesses can fact check me on this, but they're -- they're utilities of the customers for those. But they are sort of -- they were the product of a state-mandated procurement.

COMMISSIONER KEMERAIT: And then same question for Empire Wind One and Sunrise Wind; do you know who the parties to the PPAs are for those as well?

MR. KAPLOWITZ: I belive for those, it is the state. Again, I can -- I can fact check that but I think it's the -- sort of the New York entity that sort of runs offshore wind procurements. But I guess -- no, it's NYPA. The New York Power Authority would be the ultimate customer for those -- those contracts.

COMMISSIONER KEMERAIT: That's for both of the last two?

MR. KAPLOWITZ: Yes, I believe so.

COMMISSIONER KEMERAIT: Okay. Thank you.

MR. KAPLOWITZ: I will verify and correct the record if I'm mistaken.

COMMISSIONER KEMERAIT: Thank you. Any

clarifying questions?

(No response.)

COMMISSIONER KEMERAIT: There are no further questions but thank you for your presentations and you may step down.

MR. KAPLOWITZ: Okay.

MR. SMITH: Presiding Commissioner Kemerait, Mr. McAleb has a short presentation. Do we have any time for him?

COMMISSIONER KEMERAIT: We are -- we are out of -- we have -- 15 minutes is up. I did ask about probably two minutes of questions during the earlier presentation, so if you can proceed for about two minutes, we will allow that.

MR. McALEB: Thank you, very much. Thank you, very much. I am Bill McAleb. I am with Walker & Associates and represent -- I'm representing here the Environmental Defense Fund. I'll be very brief.

Maybe some of my focus is a bit different that you may not have heard much yet about, but it -- it -- it focuses on the intended orderly transition as put in the -- in the plan for a bridge that -- that takes from emissions to no emissions and makes a few stops along the way. Primarily, the, you know, the exit of -- of coal generation was -- was a focus of mine and then the movement from -- from that to -- to the use of hydrogen, effectively, natural gas then hydrogen, both a blend and then ultimately go 100 percent hydrogen.

But it's really an embracing of the next generation -- oh, I'm sorry. Next slide, please -- next generation of natural gas, hydrogen-capable combustion turbines. That is kind of -- of real concern, I think.

The -- I may, given the time I've got left, I may just jump around quite a bit but the -- but the bottom line is that the combustion turbines that Duke is proposing, they've couched at advanced class and also hydrogen capable. Right now, today, they're 50 percent hydrogen capable, according to the OEMs who actually build these things with an expected forecast of -- of a hundred percent capability of hydrogen used for fuel.

What does that mean? It means that you're going from -- not only when you go from coal to natural gas, of course that's a reduction in emissions. When you go from that to a 50 percent blend, it's a similar reduction and then finally to hydrogen, you're emissions free.

But the real concern really is the part that Companies left out in the plan, and it talks beyond their -- their service territory, kind of beyond their fence. And it's about what about a hydrogen economy -- well, a marketplace, what are the issues and concerns with that? And there's a lot of them. There's not one pipeline in this country that currently moves and transports natural gas that is going to be capable of transporting hydrogen.

Why is that? It has nothing to do with -- with aspirations or intent or any of that sort of thing. It has to do with science and it has to do with the materials. The fact of the matter is is that every pipeline in this country that transports natural gas is made of carbon steel. And carbon steel is subject to something called hydrogen stress corrosion cracking.

You say, well, what is that? It's about -- it attacks intergranular boundary energy at a molecular level and it chews away. And as it turns out, it continues. It doesn't matter whether it's a little bit of hydrogen or a lot of hydrogen. It's -- that just is dialing the knob on the radio that says how fast will it occur. You're going to get leaks and potentially catastrophic events as a result of putting hydrogen in a pipeline.

So a quick way of saying, you know, that the pipelines that are out there right now, regardless of any those -- if there's a number of different studies that are ongoing for a variety of different entities that looking at what is the -- what's the right percentage? If you look at the -- at the specifications for transportation on any gas pipeline -- any gas pipeline, it talks a lot about the fact that it needs to be methane.

It's not -- it doesn't say anything about hydrogen. In fact, when it does say something about hydrogen, it's talking about it in terms of parts per million. That's nowhere close to anything that we -- that you may have seen or heard or read about in any -- in any sort of news article with -- with this topic. 600 parts per million is pretty dog-gone small, way less than one percent.

And at the end of the day, right, that -- it's there for a reason. Those pipelines are for for-profit entities. There's not one that I know of, and certainly not the primary one that provides natural gas to this part of the country, that being Transco, and the fact that -- that they're bringing on more natural gas throughout the southeast.

Supply enhancement is a good idea -- a good thing, but the bottom line is, what are you going to do when -- whether the -- the combustion turbines are 50 percent capable or maybe they even make to a hundred percent capable, when you don't have a market, you don't have, you know -- how do you make it? How do you make hydrogen?

Can you make it inside the fence? Yes. And can you use -- can you use renewable energy? Yes. But the bottom line is, is how clean is that energy? How -- what does it take to make that energy? I'd argue that solar and wind are certainly in the -- in the no emissions category, which is a real benefit to making hydrogen. Can you make enough? Is it reliable enough? And that's kind of a quick talk about what's -- what was in my testimony. I'm happy to entertain some questions for you. Sorry about the quick -- the quick dancing here.

COMMISSIONER KEMERAIT: Thank you for your -- your abbreviated presentation. I think we -- we all -- we all heard a lot even though it was abbreviated and let me check to see if there are any questions.

(No response.)

COMMISSIONER KEMERAIT: No. So thank -- thank you to both of you and you both may step down.

MR. KAPLOWITZ: Thank you.

COMMISSIONER KEMERAIT: So I believe that it's TotalEnergies that that is next.

MR. BURNS: Commissioner Kemerait?

COMMISSIONER KEMERAIT: Yes.

MR. BURNS: We have a quick question, just for those of us who were a little later on and trying to make sure our witnesses were here, do you -- when do you expect to take the one half-hour break for lunch and do you think it'll be before or after 12:00?

COMMISSIONER KEMERAIT: Our plan is to, based upon the time of the 15-minute presentations, we expect that we are going to be completed before 1:00.

MR. BURNS: Okay.

COMMISSIONER KEMERAIT: And so we are going to be taking the break, a half an hour lunch break as soon as we are completed. And I think that it's going to be at 1:00 or before 1:00.

MR. BURNS: Thank you, very much.

COMMISSIONER KEMERAIT: Okay. Thank you. You may proceed as soon as you're ready.

MR. TANNER: Yeah. Thanks. My name is Matt Tanner. I'm with the Berkeley Research Group here on behalf of TotalEnergies. I'm here to talk about the the path to offshore wind, hopefully building on what Dr. O'Brien talked about and Mr. Kaplowitz. He had a different perspective on a few things.

My background in offshore wind is probably over the last decade, you know, quite a bit of experience with utilities, you know, how it contributes to the decarbonization pathways. And then a lot of experience sort of up and down the east coast in terms of the commercial side of offshore wind and then what has to happen for it to move forward and sort of be financially feasible, you know, both for customers and for the developers.

Next slide, please. So heard a lot, obviously. I mean, it's the -- the biggest piece of the CPIRP, you know, the big load growth that came through, you know, a lot of signed contracts for industrial loads and data centers. You know, and I think, you know, it's important to point that that's happening everywhere across the United States right now. It's not just Duke.

And so, you know, there's obviously uncertainties around it, but it seems that it's uncertainty that everyone's facing the same challenges. And in general, I think Duke is, you know, very correctly pursuing all of the above strategies, you know, trying to mitigate technology risk, trying to help customers. And I think from, you know, reviewing this testimony and making it through, I mean, it's very notable that there is now, you know, 2.4 gigawatts of offshore wind that's needed by 2035 -- you know, honestly, ideally, even earlier, as Mr. Kaplowitz was talking about.

And I think in the perspective of offshore wind, you know, the focus is no longer, you know, questioning whether offshore needs to happen or that sort of thing. I mean, it really is, you know, what can be done to ensure that it's, you know, built on time. And of course, built cost-effectively, you know, by the time it's actually needed.

And so the -- the fundamental point of all of my testimony are kind of recommendations and suggestions that I -- that I hope will help on that view of, you know, how can you get to, you know, good, effective contractual relationships that lead to offshore wind being built by the time that it's needed.

Next slide, please. So I think -- I mean, I think that people have talked about these sorts of things and so the benefits of offshore wind. I think it's worth highlighting a few others that I would note. I mean, I think one, I mean, the Coastal Virginia Offshore Wind Project is a great example of an effective project. It was planned well. It's effectively procured. It's on budget. It's on schedule. And I think a lot of my recommendations kind of stem from how can you take that process and apply it to -- to North Carolina and Duke.

You know, offshore wind, as mentioned, I mean, has very good characteristics for industrial and load center data. You know, those have very high load factors. They get a lot of reliability. You know, offshore wind, you know, has a high capacity factor. It provides ELCC. Its effective load-carrying capacity is in the 70s. I think very usefully, it doesn't decline that quickly, at least up to 3,200 megawatts as shown in Duke's CPIRP. And I think it does ingrate well with, you know, the nuclear that Duke needs, the gas that Duke needs, the solar, the batteries. I think they're all part of the way that you meet this sort of rising load, high capacity, you know, high -- high load factor needs that are coming.

Next slide, please. So with that, I want to talk a bit about, you know, the development pipeline. You know, and again, it is a -- it's a big industrial infrastructure project. It takes ten years at least, you know, maybe -- maybe it could be done a little bit quicker, but it is a -- it is a complex process. You know, Dominion, for example, built their own Jones Act battleship to -- to be able to deliver the -- the turbines.

And so, you know, what I put up here is a -- is a timeline, you know, starting with year one. You have the lease award and the permitting for surveying. That's sort of where the three offshore leases are solved. You know, they -- they need to get to years two through four, which is the environmental studies, the site surveying. You know, Duke -- Duke probably needs to finalize the transmission sign ASAP because transmission takes time, as well as initial site designs. And that leads to what was discussed in sort of the years five through seven, which is, you know, the big environmental reviews. You have the final site surveying and permitting, you know, getting ready for the actual construction.

And so I think from the perspective of

how to advance offshore wind, I mean, it is a phased project, you know, I think in terms of, you know, allocating resources, allocating money, you know, putting things into the rate base, you know, it can be phased in. But, you know, the environmental reviews can't occur before, you know, all these other steps that do cost some money. And certainly, construction can't start before the environmental review is finalized.

And so it's important to -- you know, what I'm recommending is that the -- you know, that Duke requests but also the Commission directs Duke to, you know, start doing some of those -- start doing some of those activities so they can move forward.

Next slide, please. I wanted to highlight -- I mean, it's just worth -- it's a notable point that in the -- in Duke's request, you know, there's significant funding for some of the other long-time resources, and I do think that funding is appropriate. I mean, they're long time -- you know, long-lead-time resources. They have the same sort of stage development that offshore wind has.

I think my concern is that the -- the ARFI, it doesn't -- as currently stated, it doesn't necessarily advance offshore wind quickly enough. I think that there is a -- a significant risk of, you know, just a direct two-year delay from how it's currently stated.

And so a lot of my recommendations are, you know, what can be done in parallel with data gathering? What can be added to the ARFI so that offshore wind is also moving forward?

Next slide, please. Then same thing on costs and cost mitigation. I mean, it's -- it's obviously an extremely critical point with -- with any, you know, big utility project. It's a lot of -- it's a lot of costs that are going to be ultimately paid by ratepayers. The IRA, the Inflation Reduction Act, you know, has a very generous ITC for offshore wind. You know, depending on characteristics, 30 to 50 percent of total -- total investment. You know, same -- same benefit for nuclear or offshore wind.

You know, one -- one concern that I have is Duke -- Duke is -- assumes in their modeling that the the IRA funding and the tax credits are extended. But the law as currently written, you know, the tax credits start to expire in 2033, meaning that if the projects don't begin construction by then, there's a risk that they would start to phase out and go down to zero, which is just a one-for-one increase to costs. And so, you know, I think my recommendation is, you know, it's certainly possible that this credit could be extended. I mean, it's happened before with -- with previous ITCs and PTCs. But if at all possible, it's a big benefit -- it's a big risk mitigation benefit to begin construction before 2033, sort of lay the process just to make sure that these very important tax credits get received.

I think that same point holds for any other resources. It holds for nuclear. Holds for, you know, onshore wind. It's just a -- it's a risk that I don't think it's worth -- you know, I don't think that Duke or North Carolina wants to take unless, you know, we hear something different from Congress about the extension.

Next slide, please.

COMMISSIONER KEMERAIT: And before you

go to the next slide --

MR. TANNER: Yeah. Of course.

COMMISSIONER KEMERAIT: -- your last bullet point talks about when construction needs to begin and it says that making year 2025 the latest possible year to start the -- the project. Can you -- can you just explain what you mean specifically about start the process? What -- what will you be asking for in 2025?

MR. TUCKER: If you don't mind if I go to the next slide?

COMMISSIONER KEMERAIT: Sure.

MR. TUCKER: I will answer that question. Appreciate it.

Okay. So this slide is actually what am I asking for and what are my recommendations. So I think -- I think there are actions in '24 and '25. It's -- it's not from the whole process. You know, 2,400 megawatts of offshore wind is a, you know, multi-billion dollar project that's not a -- not something that gets allocated all at once.

I think first, you know, I would recommend that Duke request and the Commission approve, you know, up to $200 million for near-term development activities. This would include funding of, you know, contract negotiations, site surveyings or leading up to the -- leading up to the environmental review. It would also fund, you know, onshore transmission design and sort of getting ready for the construction of that.

You know, I think -- I think the goal there is given the timeline, especially for the transmission, that, you know, that takes time itself to be -- to be built, to be designed and built; that if the early design was started as early as next year, you know, there actually is time for that to be, you know, constructed in time for the offshore wind.

The second two recommendations I have are tied -- are tied together and I know both Dr. O'Brien and Mr. Kaplowitz mentioned these. You know, the developers -- you know, all three of the developers really do need a structure procurement process which could be part of the ARFI. You know, just the end point of that ideally would be, you know, here is the -- here is the structure for, you know, when offshore is going to be, you know, be built, when these -- you know, when these elements are going to go forward, how that -- how cost recovery is going to occur as part of that.

You know, I would recommend that Duke, you know, start commercial -- commercial discussions with developers. Again, part of the structure procurement process, it's not contracting for the full 2,400 megawatts. It's not the final, you know, ownership structure PPA. It's, you know, a complex process designing how does that structure look. You know, and that can be done over the next, you know, 18-24 months, which would then lead into, you know -- you know, actual final contracting in the '28-'29 time before construction begins.

Does that answer your --

COMMISSIONER KEMERAIT: Yes, thank you.

MR. TUCKER: Okay. Next slide, please. I think I'll skip this. It's just a little more on the timeline. So next slide. Just to touch about TotalEnergies, it's -- it's sort of in line with, you know, offshore wind being mature, a mature technology. They they -- they are -- they have 16 gigawatts, right under 16 gigawatts, you know, under construction or under development, as well as, you know, multiple gigawatts of operation. And so again, part of the offshore wind is a, you know, mature global technology that, you know, can be can be built and sort of the process of no -- you know, Total is an example of someone who has successfully done that. So that concludes my...

COMMISSIONER KEMERAIT: Thank you for your presentation. Let me check to see if there is any clarifying questions.

(No response.)

There aren't any. So again, thank you. You may step down.

MR. TANNER: Thanks for the time.

COMMISSIONER KEMERAIT: Mr. Burns, I'm going to follow up with your earlier request. I have looked at the intervenors that still need to make their presentations. And we are not going to be completed by 1:00. So we will hear from one party and then we will take our -- we will proceed next with -- I believe it's Avangrid Renewables. And then once Avangrid has presented its presentation, we will take the thirty-minute break.

MR. BURNS: Thank you, very much.

MR. SMITH: We call Mical Nobel, Betsy Andrews and Jeffrey Bower to the stand.

There are a couple of typos here. It's Ms. Nobel and it's Dr. Andrews, for what it's worth.

COMMISSIONER KEMERAIT: Okay. Good afternoon now. So you can go ahead and proceed when you're ready.

DR. ANDREWS: Thank you. Good morning or good afternoon. Yes, thank you. We have two short presentations to present between the three of us. My colleague will proceed.

MR. BOWER: Thank you. Good afternoon. Thank you for the opportunity to present to the Commission today. My name is Jeff Bower. I'm a managing consultant to Daymark Energy Advisors.

Actually, if you could go to the next slide. Daymark is an economics and engineering consulting firm focused on the North American electric and natural gas markets. We're headquartered in Worcester, Massachusetts. We have employees across the U.S. and Canada.

I work primarily in our clean energy and regulatory economics practice areas. I focus on cost benefit studies for transmission and renewable projects, integrated resource planning, as well as market price forecasts and that sort of thing. As an aside, I'm also a graduate of the Nicholas School of the Environment, Duke University, so it's great to be back here in the Triangle. Today, I'll be summarizing for you at a high level the key conclusions from my direct testimony.

Go to the next slide. So my testimony in this proceeding relates to the benefits of offshore wind as a key component of the Companies' resource plan. Offshore wind provides an important source of non-emitting generation to meet Duke's growing load while also achieving resource adequacy while also making progress on the important emissions reductions targets for North Carolina.

Duke's supplemental planning analysis provided important conclusions related to offshore wind. Modeling results show that a significant build-out of offshore wind is a key component of the lowest cost resource planning for all of Duke's primary scenarios. While Duke's preferred portfolio has offshore wind with a target of 2.4 gigawatts in 2035 as I discussed in my testimony, accelerating the development of offshore wind would allow the significant benefits of the resource to accrue to customers sooner and provides important optionality for future resource planning decisions and provides important risk mitigation for Duke's resource plan to customers.

The first component of that risk mitigation is the optionality to address load growth uncertainty. When Duke experienced the rapid load growth that necessitated the supplemental planning analysis, the additional resource built-out driven by the new load was primarily offshore wind and combined cycles with smaller amounts of additional solar in storage.

And given the long-lead-time of offshore wind development, it may be difficult to ramp up development on short notice if unexpected load growth continues to materialize. And if the options to expand other clean energy resources are similarly constrained, this will pose an additional planning challenge to Duke in the coming years.

The second area of risk mitigation relates to the fact that earlier deployment of offshore wind can help mitigate future delays in other major non-emitting resources such as the advanced nuclear. Several witnesses have discussed this -- this issue previously today, but the Companies' planning to bring new nuclear online in -- by 2035 to meet some of the emissions reductions requirements and it's clear that nuclear is major component of Duke's long-term plan to meet carbon neutrality by 2050.

While there's a lot of development activity happening with new nuclear designs and the small modular reactors, there is tremendous uncertainty as to when those resources will be -- will be available and what cost. So by deploying offshore wind as quickly as possible, it bides Duke some time to respond to evolving conditions in that market. If availability of new nuclear units is delayed or if costs are higher than expected, the Company could adjust its plans to pursue additional offshore wind or other resources while still achieving the emissions reductions requirements.

And the final point that I make in testimony related to risk mitigation is the potential for underutilization of fossil resources. It's another topic that's been discussed by a couple witnesses today. But as I previously mentioned, when Duke refreshed its analysis in the supplemental planning analysis to consider the additional load growth, the additional identified resources were primarily offshore wind and the combined cycles. Since offshore wind is an integral part of the long-term carbon reduction portfolio, Duke could accelerate deployment of offshore wind and potentially defer or avoid construction of new combined cycle units. This would provide some benefits to customers if it would avoid the capital investment that may ultimately be underutilized in the long term.

And then lastly, I -- as I discussed in my testimony, accelerating the development of offshore wind will have only a minor impact on rates. The majority of my testimony in this matter relies on company's confidential work papers, so I won't discuss it in the open session here today. But I just wanted to highlight here that by the Companies' own analysis, acceleration of offshore wind by comparing a couple of the different scenarios that they ran has a temporary and minor impact on rates. This means that accelerating offshore wind development will be a low regret step to addressing the load growth while also making important progress on meeting the emissions reduction requirements.

Thank you for the opportunity to present to you today. I'm happy to answer any questions.

MR. SMITH: You can advance to the next slide deck, please.

DR. ANDREWS: Thank you. Good afternoon. I'll be presenting about the Kitty Hawk offshore wind projects and my colleague will advance with a final slide on our -- our recommendations for the Commission today.

If you could go to the -- yeah. Thank you. The Kitty Hawk offshore wind projects are being developed within the global context of the

Iberdrola Group's experience and decades of technical expertise. We are also then fully informed by our local experience in the United States by our Vineyard Wind One project of what it really takes to develop and then move to construction of a project in the U.S.

Next slide, please. Avangrid acquired the original Kitty Hawk lease area which was then OCSA 0508 in 2017 as part of a BOEM lease auction for only $9 million. And that small sum of money really helps to underpin the significantly advantaged business case behind this project.

In November of 2023, Avangrid requested the segregation of the lease area into two sections. The northern third of the lease area became designated OCSA 0559 and that's held by Kitty Hawk North, LLC. The remaining southeastern two-thirds of the site stay under that original lease area designation OCSA 0508, and that's held by Kitty Hawk Wind, LLC. But typically, that's what we refer to as the Kitty Hawk South Project.

That segregation was undertaken to really advance Avangrid's ability to generate a pathway to market for each of these projects.

Avangrid have owned these lease areas since 2017 and we are committed to making forward a pathway to market for this very valuable clean energy.

The Kitty Hawk lease areas are very favorably sited in terms of opportunity to generate energy. Their siting about 27 miles off the coast of Corolla means that the turbines will be minimally, if at all, visible from the coastline. They have shallow water depths and well-suited ground conditions, which means that we can use industry standard technology for the engineering and final installation of wind farm assets. That de-risks these projects and really, again, substantiates the favorable business case behind them.

The projects, maybe most importantly, have very strong and consistent wind speeds which create a high net capacity factor or overall efficiency of the energy generation in the projects. And interestingly, I think the Metocean historical record shows that they are really well-protected from hurricane -- hurricane strength wind speeds, which, again, de-risks the projects.

And next slide, please. Avangrid are developing two different potential offshore export cable corridors to connect into -- sorry -- interconnect into North Carolina. One of these cable corridors, as you can see from the map, has an interim cable landfall in the Outer Banks and then an additional inshore section of sub-sea cable which goes through Pamlico Sound.

Avangrid are keenly aware of the potential engineering and environmental concerns which may arise from rooting that sub-sea cable through Pamlico Sound and we're continuing to evaluate how that could be developed responsibly. However, at the same time, we are maturing the alternative cable corridor which is fully offshore and makes cable landfall just south of the Outer Banks at Atlantic Beach. Importantly, either of these offshore cable corridors have really well-suited onshore cable root options to bring that energy to interconnect at New Bern. As you'll see from the map, we are also diligencing and maturing a potential offshore cable corridor that makes landfall in Virginia Beach to the north. And that would allow the projects to interconnect into PJM.

Moving on to the next slide, please. Summarizing these two projects in a table, you'll see that the Kitty Hawk North Project has an overall generation capacity of about 800 megawatts and 1.1 gigawatts, whereas the Kitty Hawk South Project has a capacity of 1.6 to 2.4 gigawatts. The difference between those two is really just down to the number of wind turbine generators or WTGs we're proposing for these projects. We're looking at up to 56 WTGs for Kitty Hawk North and 121 for Kitty Hawk South.

And the reason you see a range in capacity for each of those projects is because we are still evaluating which wind turbine model should be eventually used. That final decision, the selection of the WTG will depend on the ultimate engineering of the project, as well as what's available on the supply chain at the point of construction.

Because of that range in capacity for each project, we are looking at one offshore substation or electrical services platform for Kitty Hawk North and up to two for Kitty Hawk

South. Assuming that we're bringing this energy into North Carolina, we'd be reliant on high voltage direct current, or HVDC technology for the cable transmission offshore. HVDC technology offers real advantage in terms of low transmission loss across longer cable lengths. And it also creates a lot of technical and cost-efficiency behind higher capacity energy projects.

Moving on to the next slide, please.

COMMISSIONER KEMERAIT: And a real quick question before you move on to the next slide. What are the capacity factors for Kitty Hawk North and Kitty Hawk South, if you have that information?

DR. ANDREWS: Yes. So we're looking at a range of 800 megawatts to 1.1 gigawatt for Kitty Hawk North and one point -- sorry. Make sure I say the right thing. Sorry. And -- sorry. It's there. 1.6 to 2.4 gigawatts for Kitty Hawk South.

COMMISSIONER KEMERAIT: Do you have the actual capacity factors for those?

DR. ANDREWS: Oh, sorry. In terms of NCF?

COMMISSIONER KEMERAIT: Yes.

DR. ANDREWS: I think that is still in engineering. It will depend on the final layout of the wind farm and that final turbine selection. But in our diligence, we've been looking at a net capacity factor of sort of 42 to 45. But again, that is very nominal and based on preliminary engineering.

COMMISSIONER KEMERAIT: Okay. Thank you.

DR. ANDREWS: Thank you. Sorry. Moving on to the schedule slide. Thank you. So I think what you can see from the schedule slide is how far advanced we actually are through our federal permitting. There's a huge amount of data acquisition and development of this project both in terms of engineering and permitting documentation and review that has happened for both projects. Kitty Hawk North has a construction and operations plan submitted to BOEM as a key milestone in our federal permitting and we have logged all of the geophysical, geotechnical and benthic data associated with that. And that really supports then what we see as a strong potential to make commercial operations date or COD for this project by 2030.

Could you advance to the next slide, please. Kitty Hawk South is in a similar position but a little bit behind Kitty Hawk North. We have submitted a matured construction and operations plan to BOEM and we have acquired reconnaissance-level G&G, geotechnical and geophysical data, for this project. However, to advance our federal permitting to acquire the remaining bulk of that geophysical and geotechnical data and to complete the engineering required under that federal permitting process, Avangrid really needs certainty on pathway to market. We need to be able to justify that this is investment prudently spent at this point in time.

Should Duke move forward towards acquisition, that would stimulate all activities required to maintain the project schedules you see here, a 2030 COD for Kitty Hawk North and a 2032 COD for Kitty Hawk South.

MS. NOBEL: Okay. Can you advance to the next slide, please. And I know I'm the last one up before lunch, so I'll keep it brief.

Just to build on what my colleagues have said and what others have said earlier today, North Carolina has, of course, set bold and ambitious clean energy targets, including House Bill 951, and everyone, including us, wants to make sure those goals are met. We are very excited about the role that offshore wind can play, which Mr. Bower spoke to earlier. And we believe that we at Avangrid can hugely help with our Kitty Hawk project and our nation-leading experience.

We commend Duke for including offshore wind in their recommended portfolio in the updated portfolio -- in the updated CPIRP. And we encourage the Commission to accept a minimum of 2.4 gigawatts of offshore wind as part of the final IRP. However, the near-term action plan proposed for offshore wind development is just not concrete enough to ensure that these offshore resources remain available for the state's needs, as Dr. Andrews was just saying, and not concrete enough to ensure that we progress on the schedule enough to meet the interim targets.

So in order to get North Carolina where

it needs to go, we are recommending more immediate and concrete action pertaining to offshore wind. In our testimony and on this slide, we've outlined a few potential steps that we recommend as to how the Commission may facilitate a conclusive and third-party run procurement process that may begin this year. This timing would enable project selection by mid-2025 and final negotiations between Duke and the selected developers -- or developer/developers, as well as approvals by the Commission on a schedule that creates more clarity going into the next CPIRP update instead of continued ambiguity. So I will stop there and we would welcome any questions.

COMMISSIONER KEMERAIT: Okay. Thank you, very much. I don't see that there's any questions, so we appreciate your presentations and you may step down.

So we will take -- my notes show that the next intervenors who will be providing presentations are Tract Capital Management first, then the Carolina Clean Energy Business Association, then the Clean Energy Buyers Association, and finally, Appalachian Voices.

So we will take a 30-minute break and we will come back and be on the record at 1:05.

(At this time, a recess taken from 12:36 p.m. to 1:06 p.m.)

COMMISSIONER KEMERAIT: Okay. Good afternoon. We are going to go back on the record and we will continue with this Technical Conference.

The next party that will be presenting testimony is Tract Capital Management.

MR. MOE: Good afternoon, Commissioners. Thank you for the opportunity to talk with you today. I'm Ronald Moe from Leidos Engineering on behalf of Tract.

Next slide, please. Let me take a minute to introduce you to Tract. Tract is a data center land acquisition and development Company that desires and intends to develop a number of data center campuses within the Companies -- within Duke's North Carolina franchises, service territories, and has had ongoing discussions for over a year with Duke about those campuses. So a 500 megawatt campus that they intend to bring online in 2032 and up to 2,500 megawatts in -- in multiple locations in the mid 2030s.

Tract's interest in this proceeding is based on conversations that they've had with Duke. They're concerned that the Companies may not have enough generating capacity online in those time periods to be able to satisfy both their future loads as well as they know there are competitors who are also seeking on loads and so they're concerned about that. I want to emphasize my pre-filed testimony, as well as this presentation, are focused exclusively on the load forecast and the consequences of those -- of those load forecasts on the selected portfolios.

Next slide, please. So the -- the analysis underlying these conclusions is laid out in my direct testimony, the two sets of conclusions. The first is that the -- the approach that the Companies use to develop the forecast of large site development loads likely caused that load forecast to be too low, based only on the information that the Companies had at the time, not looking back at it today, not looking back at it -- from some other point in time, but even just at the point in time where they developed it.

That approach, I think, can be summarized in the two sub-bullets they selected -- their words -- a rarified group of projects whose, quote, demand could be anticipated with a high degree of certainty, evidenced by advanced discussions with the Companies about taking power, as well as other indicia of development. And then they further discounted the loads for -- for that small, rarified group with fairly certain loads to -- to come up with the final load forecast for that group.

There is, as -- as previous witnesses this morning mentioned, there is -- there is a lot of uncertainty in load forecasting. There is especially a lot of uncertainty when loads are changing quickly and when new kinds of loads are showing up. There are -- there is uncertainty in the -- in the forecast of residential, commercial and industrial loads that is developed that the Company develops using econometric models.

What I want to emphasize is that this standard of addressing uncertainty, having a high degree of certainty, that is almost destined to create a forecast that's too low. The only way you'd get a high degree of certainty that a load is going to be at least that high is to underforecast. That's not the way they forecast residential, commercial and industrial loads. They -- they try -- and I think do a pretty good job of forecasting what they think is the expected load.

Here, I think they -- they established a different standard and instead forecast a load that they were fairly certain would be met or exceeded, not -- not met and maybe fallen below. And I think that approach, on the -- on the face of it, I think they had to know at the time they were doing it. At the time they wrote the paragraphs in the CPIRP document, that that approach was likely to lead to an underforecast of -- of the actual loads.

If you could turn one more slide. We have to give, I think, the Companies credit for coming back to you in late summer/early fall last year and saying, "Look, we've got new information about these large site development loads. We need to develop -- we need to provide you a new load forecast and we need to provide you new plans." They're attempting to stay on top of something that is moving quickly.

Having said that, I think they were correct in using the same approach that they had in the spring to -- to determine that they had a problem, that they had underforecast in the spring. But then, having determined that there was a problem, they did not have to stick to the same methodology. And yet, they used the same methodology, the same selection criteria to come up with a new rarified group whose loads they were fairly certain would achieve -- would actually occur. And -- and that forecast also, even though it's now 3000 megawatts in the fall 2023 forecast for the year 2033 instead of 1,300 megawatts, even though it increased substantially, it -- just the methodology they used, again, is likely to lead to a forecast that is too low.

The final conclusion is that I think they should also be applauded for providing a high case last fall that includes another 1,360 megawatts over and above the 3,000 that I just mentioned. These are all 2033 coincident peak loads. They should be applauded for that, and from my perspective on the analysis, backing this up is in the testimony. I think that's the most likely forecast that Duke has provided to -- to you. And I think selecting a portfolio based on that forecast is -- is much more prudent than selecting a portfolio based on any of the other forecasts, because those other forecasts, in my opinion, are unlikely to be able to satisfy the load.

So last slide, please. I have -- I have three recommendations. The last two have, I think, been covered pretty well by earlier witnesses, so I won't dwell on them unless you have questions. So the first -- the first recommendation is essentially what I just said. I think the Commission should only approve a portfolio that's based on the continued economic development 2023 fall high load forecast. I think any other portfolio is unlikely to actually be able to meet the loads.

With that, I'm happy to take any questions.

COMMISSIONER KEMERAIT: I do have one

clarifying question for you, Mr. Moe. Your second recommendation is to order the Commission -- that the Commission order the Companies to improve the methodology. And can you just explain a little bit more about in what way you believe that the methodology needs to be improved?

MR. MOE: Certainly. And a written explanation of this, we provided to Duke, I think last Monday in response to one of their data requests, so you'll have that in writing.

I think there are two approaches. The first one is the one that Dominion Virginia has been using, which is they have very close relationships with the largest of the data center developers and operators and have been working with them to develop forecasts. They also have a time series because they've been doing this data center development for about ten years. I think that's really the state of the art for utilities that have a track record of serving data centers.

I don't think Duke is there yet, but I think they should continue -- Duke should continue to kind of monitor what Dominion Virginia is doing because at some point, they probably -- Duke probably will be in that situation. I think until then, the approach that Georgia Power used in their 2023 IRP, which was to take the full list of all of the data center companies that had reached out to them and made -- essentially, submitted a letter saying they were interested, potentially, in siting within the Georgia Power territory, keeping track of those closely, keeping track of what milestones they had reached, and then when it came time to develop the load forecast, attaching probabilities to each of that -- each of the members of that long list and developing an probabilistic load forecast based on that pretty comprehensive data set.

I think that is probably the -- the state of the art for utilities that are in this fairly early period like Duke is, and I think one of the witnesses this morning made the same recommendation. So I think we are in alignment there. Does that answer the question?

COMMISSIONER KEMERAIT: It answers the question and thank you, very much. Let me check to see if the Commissioners have any questions.

Commissioner McKissick.

COMMISSIONER McKISSICK: I guess you were able to answer Commissioner Kemerait's question as relating to a better methodology, you know, and of course, you pointed to Dominion. But could you be more precise in terms of stating what Dominion actually does differently? Obviously, they have one of the -- from what I gather, the highest concentration of data centers in the entire country. So they've had that demand that's been increasing, I suppose, rather rapidly, but there was some consistent period of time where they have had an opportunity to kind of better gauge it, judge it, see what comes to -- comes to fruition, as opposed to what is just proposed.

But what is it that they do differently, if you could provide some greater degree of specificity?

MR. MOE: I'll try. This is based solely on -- on my understanding of publically available documents so it may not be complete. I think they use kind of three prongs. So -- so first of all, they've been connecting data centers for more than ten years and have a time history -- a time series of historical data that -- that they can analyze in a way that's analogous -- not perfectly, but analogous to how Duke analyzes the residential sales data that they have.

And so they can develop a -- a forecast kind of from -- a top-down forecast based on historical data. Duke does not have -- certainly does not have that luxury at -- at this moment. There's not that time series available to them.

Secondly, they have very close relationships with the small number of data center developers/operators that currently comprise, you know, 80 or 90 percent of the data service load in their service territory. They're talking with them all the time. Those companies are making plans to expand either their current sites or -- or additional sites. And so, they've got essentially inside information that they can use to assemble a forecast. And then they also do statistical analysis of the loads for individual companies. And from what I understand, discuss the forecasts that they've derived for, say, Microsoft with Microsoft and ask, you know, "Does this make sense or -- or how should we adjust it?"

So I think they've got those -- those

three ways, but then at some point, they have to combine and some subjectivity comes in at the end. But they've got kind of a wealth of information that no other utility in the country currently has.

COMMISSIONER McKISSICK: That's helpful. I can see where that historical perspective would certainly be of great value along with the other --

MR. MOE: As well as the relationships.

COMMISSIONER McKISSICK: -- the other relationships you've identified. Thank you.

MR. MOE: Mm-hmm.

COMMISSIONER KEMERAIT: Mr. Moe, thank you for your testimony. I think that's all the questions and so you may step down.

MR. MOE: Thank you.

COMMISSIONER KEMERAIT: Next up is the Carolina Clean Energy Business Association. Mr. Burns?

MR. BURNS: Yes, ma'am. I'm just going to put my cards out for my members.

Madam Presiding Commissioner, we -- we present three witnesses in your testimony that was filed with the Commission. There is only two, Mr. Hagerty and Ms. Miller, who will be presenting during this portion of the -- of the technical conferences. But we wanted to make sure that Mr. Newell was available in case any of you had questions directed at his earlier prior testimony, so...

COMMISSIONER KEMERAIT: Thank you.

MR. BURNS: Yes, ma'am.

COMMISSIONER KEMERAIT: You may go ahead and proceed.

MR. HAGERTY: Good afternoon and thank you, so much, for giving us this opportunity to present to you. Today, I will be presenting on the value of solar that we see in the CPIRP portfolios, as well as the need for proactive transmission planning.

Just to quickly introduce myself, my name is Michael Hagerty. I'm a principal at The Brattle Group where I've worked for eleven years working on these types of issues. Specifically, over the last three years, I've been involved with analyzing and modeling the need for resources in the Duke territory, both to serve load reliably, as well as to meet the HB 951 goals.

I have also participated in the last -- the 2023-2024 transmission planning processes and have a broad experience of working on these processes across the country. And I think there's a great opportunity here in North Carolina to implement some of those improvements that we've seen across the country to drive to the lowest-cost outcome for ratepayers here.

Let's see. On the next -- here we are. Just -- just had to locate this guy. So the first slide here, the key takeaways here is that solar and storage are cost-effective components of all of the CPIRP portfolios. And I have not done my own analysis in this case, but -- so I think it would be reasonable to ask: How do I know that?

And we know that by looking at the analysis that Duke did. They ran a model called EnCompass. It's a capacity expansion model that is intended to identify the resources needed to reliably serve load, meet the GHG reduction requirements and do so at the least cost to ratepayers.

And the results of that are -- are very

clear and you can see that in the top-right here, where for the four portfolios, there is a very high level of both solar and storage. Across the four portfolios by 2035 is 11,800 megawatts to 14,900 megawatts of solar. For storage, there's 4,300 megawatts to 6,700 megawatts. So this highlights that even with recent increases in costs, this is a cost-effective resources -- resource -- both of them are cost-effective to meet the needs of the system.

The additional finding when you look into the results here, and this is shown in the bottom-right figure, is that the maximum amount of solar that was allowed to be entered into the system was selected. So this is an important finding because it shows that it's valuable uptail [phonetic] level and it also shows you that if you lifted that limit, it would likely result in higher amounts of solar. So when you set a limit on something like this, if you don't get quite the same total amount then you know, well, maybe that's -- you know, that's the amount that it needs. But if it's hitting up against these constraints, then it would be likely that additional resources would be valuable.

So why is that? Solar is selected by this model because it's the least cost source of zero carbon resources in this territory. And it's also the only clean resource that's currently being built in Duke's system. An additional benefit of solar -- and this was pointed out by the Public Staff witness Mr. Thomas -- is that these specific scenarios don't account for all the risks. And solar provides a very -- a low-cost hedge to volatile gas prices. And you can see that in some of the sensitivity analyses that Duke did, specifically around the P3 base portfolio.

So here, you see the present value of the revenue requirements across several sensitivities. One of those sensitivities did not include the carbon constraint. And there was only a 1.5 percent cost reduction due to that, but it has significantly increased exposure to volatile gas prices. And to get a sense of how at large that exposure is, in the high gas price case, that would increase the cost to ratepayers by $7 billion. And so that's from the teal blue bar there to the darker bar to the left.

So this gives you a sense of the relative scale of the -- of the cost of the solar and the carbon constraints and the value of avoiding potentially high gas prices. And the gas prices in the case were about $6 per million BTU in the short term, which is around where the prices were in 2022. So this is a very reasonable high-cost scenario.

The next point I want to make is that implementing proactive transmission planning is key to reducing costs. And this is true regardless of the resources that are being built. We've been working on proactive transmission planning processes across the country for several years and the benefits go well beyond just interconnecting of the least-cost resources. So it's really important to implement a proactive plan within North Carolina and do it effectively as possible. The benefits of that will be to reduce the total cost of transmission, reduce the generation resource costs, as well as reduce the risks created by the interconnection process.

And so the figure here -- there's a lot of information here. But I just want to step through a couple key things. In the current process, there is limited information shared between the resource planning studies and the transmission planning studies. Both of them use the same amount of load forecast, but the transmission reliability studies currently do not account for the changes in resources that are needed over the next ten years. So that requires that you identify the transmission needs through the interconnection process.

And I've highlighted here two really great developments that have been put in place over the last few years in the GI cluster studies as well as the R-zone. But what's missing is really that integration of generation planning and transmission planning.

And going to the right now, that's what I think you have a great opportunity to do and you've really set the table to do so by urging Duke to implement a proactive transmission planning study and then pursuing it through the multi-value strategic transmission plan. And the goal here should be to move the amount of transmission that's needed and planned from the generation interconnection process, which is a near-term view of the system and the system needs to the proactive 10-year-out planning process.

And that will, as I've said before, do several things. First, it will reduce the total costs of transmission that's needed. It will reduce the costs of the resources, as well as because the transmission will be prebuilt beforehand, it will reduce the risks on solar developers and other generation developers to -- to enter into the system. In some ways, you're opening the door for the resources that you are identifying that you need.

Currently when they go to the transmission system, the doors are shut. They kind of have to bang their way through in order to get onto the system. But by proactively planning, you're able to do so more cost effectively and with reduced risks.

So I have several recommendations on how to do that as effectively as possible. One is to proactively plan for that future generation load and the really key thing there is to put significant time into thinking about where would those resources show up on the system and really getting good information on the commercial interests, the land use issues, transmission constraints so that you have a good view of where resources -- the least-cost resources we've identified should be coming up.

The second is to account for the full range of transmission benefits, not just interconnecting resources but increasing the reliability, reducing the generation production costs. And there's lots of ways that this is done and we've seen a lot of ways that it's not done well.

So I think a role of the Commission is, now that this is going forward, is to make sure it's implemented as effectively as possible. And there's really great experience across the country. I would especially recommend that you look at the MISO and SPP processes to understand how that is done.

Third is addressing uncertainties in high stress grid conditions. You'll be really surprised to hear that the highest value parts or moments, times for transmission are often not included in these planning studies. So that's something that we've been trying to get more and more incorporated into planning studies.

The fourth one is to look at -- through a portfolio approach and not trying to solve one problem at a time but what does the system need as a whole. And the fifth is to also consider, not just for your system but the value of building out beyond your system into the regional planning -- interregional planning. So that's the long and short of what I've got. And look forward to any questions but will be turning it over to Ms. Miller next.

MS. MILLER: Can you pull up the next slide deck?

COMMISSIONER KEMERAIT: So Ms. Miller, you have about three minutes.

MS. MILLER: Okay.

COMMISSIONER KEMERAIT: I will give you just a little bit more leeway because I recognize -- but you're pretty close to having your -- your time limit be up.

MS. MILLER: Okay.

COMMISSIONER KEMERAIT: But I will give

you a little bit of leeway.

MS. MILLER: Perfect. Thank you. So I can be quick here. So Nicole Miller. I am an associate director at Cypress Creek Renewables. I'm here today to talk about QFs and the opportunities that we think there could be in the carbon plan.

So at a high level, there are a lot of QFs right now on the grid. About 4.2 gigawatts of solar QFs -- looks like we're still getting it up but I'll get keep going -- about 4.2 gigawatts that are on the grid today. Of those, Cypress Creek developed about 250 and we currently operate still 1 gigawatt. It's important to know that these sites came on in the mid-2010s and so as Mr. Thomas referenced earlier, they're going to be rolling off around the time of the mid-2030s, so right when Duke is trying to reach its carbon goals.

So why is this important? It's important because it -- effectively, if we allow these sites to roll off, if for whatever reason they're not active, then this is going to end up creating a sort of generation gap between where

Duke is planning its solar and where it effectively will be. So for example, if you go to -- if I go, and I just blew through my first slide in that one.

So if you look, Duke is anticipating about a 3.7 gigawatt reduction of solar QFs mid-2030s. It's just what I spoke to. And if you look at the impact, the bottom-right-hand slot -- the bottom-right-hand graphic, there is about a 4 gigawatt gap in the 2030 scenario for where Duke is trying to be and where they effectively would be if the solar sites were to not continue, for whatever reason.

So what do we do? As it stands, these -- these contracts have the ability to renew under five-year terms. These are great options for these sites, for some of these sites. For ones that are looking to invest in storage, for ones that are looking potentially to re-panel, those are simply not enough time to get financial parties comfortable with the terms so that we can actually invest the capital needed to maximize these sites.

I will say as well, you know, we had

the blend and extend program that we think was very successful. So Cypress Creek had about 600 megawatts eligible for that program. We ended up pursuing 300 megawatts. Those 300 megawatts pursued the program because of timing and because it was economic to do so. So if there were potentially another blend and extend program in the future, that is something that we could potentially take advantage of.

So said differently, we believe that these sites could be doing more. They could potentially be doing their max generation for more hours in the day and for more years in their asset lives. These sites have the opportunity to add more to the grid and we think that we should really be thinking about them as we're doing the carbon plan.

So we're here today because this takes planning. We have to start thinking today about sites in 2028 and what's going to happen with them. We ultimately recommend that the Commission issues a directive to examine the potential opportunities that these sites have to maximize the capacity at these existing interconnection points, and to ultimately ensure that Duke is utilizing the existing carbon-free resources that are on the grid today to make sure that we are maximizing our opportunities prior to investing in any additional sites.

And I think I did that in three minutes. But you can -- you can tell me if I'm wrong. But I'm happy to answer any questions or go into any further details.

COMMISSIONER KEMERAIT: So a quick question. Are you talking about maximizing opportunities -- are you talking specifically about re-powering? Is that -- is that what you're proposing for when -- when you're looking to renew the PPAs?

MS. MILLER: Yeah. That's a great question. Thank you. So re-powering is certainly one of those options. It's an option that we have looked into. I think right now, based on Cypress's view, storage addition probably makes a little bit more sense from the economic standpoint. And I will add that we did receive questions in discovery about the economics of this, so we will provide that, which will help to understand what the breakdown is.

But so adding storage, potential partial re-powering or full re-powering, if you think about it -- and if you have a site that is essentially operating at 90 percent capacity, if you can add some -- some additional panels to the site so different modules to get it back up to a hundred percent, you're effectively bringing that site and increasing the amount that it can actually produce for a longer period of time.

So whether or not that's a full re-powering, which may be expensive, I think that's kind of what we need to figure out through bringing together stakeholders and ultimately discussing what is possible for these sites.

COMMISSIONER KEMERAIT: And just one follow-up for clarification. Has that stakeholder process begun? Have you begun discussions with Duke and other stakeholders about that?

MS. MILLER: Absolutely. And so I think that's part of our question -- or part of our ask here. We believe that part of the directive of the Commission would be getting these stakeholders together. I think that there are a lot of things to be thinking about, like what can we do technically? What are the legislative and regulatory implications?

And so convening those stakeholders is going to be a key part for deciding if there is an effective program. But certainly, that's part of the ask today of the Commission.

COMMISSIONER KEMERAIT: Thank you. I don't see that there's any additional questions, so thank you for your presentations and you may step down.

MS. MILLER: Thank you, very much.

COMMISSIONER KEMERAIT: Next up is the Clean Energy Buyers Association.

MR. SIMON: Good afternoon, Chair and Commissioners. The Clean Energy Buyers Association calls to the stand Dr. Jennifer Chen for the World Resources Institute, and Ivan Urlaub, director of energy and infrastructure at energy economics.

COMMISSIONER KEMERAIT: Good afternoon. You may go ahead and proceed as soon as you're ready.

DR. CHEN: Good afternoon. Hello,

Presiding Commissioner Kemerait, Chair Mitchell and Commissioners. My name is Jennifer Chen with the World Resources Institute. Prior to WRI, I spent some time at the Nicholas Institute at Duke University, so it's really wonderful to be back.

Thank you for the opportunity to present some of the key highlights from our testimony and to hopefully take some of your questions. My testimony focused on the -- a straw-based study on resource adequacy. And for the short time that I have right now, I'd like to highlight just a few key points but also talk a little bit about the overall context. So the reserve margin, the target reserve margin, will not necessarily ensure increased reliability on its own. So you can see from this NERC definition for reliability, reliability includes not just resource adequacy but also how the system is operated.

And, you know, coming out of some of the lessons that we've learned from neighbors -- for example, PJM -- in implementing some of the incentives that improved the the operation of its fleets and in reducing the forced outage of its fleet -- the average forced outage rate of its fleets, PJM was able to reduce the required reserve margin while maintaining the same level of reliability, which, in this case, we're going to be using the same metric as Astrapé, so it's the one in ten loss of load expectation.

As you can see in this graph, this graph from the Energy Systems Integration Group from 2024 -- they're similar graphs from Brattle and Astrapé from ten years ago in 2013 -- you can see that it's at the point where we are looking at a -- a reliability level of one in ten loss of load expectation, the cost of building out a higher and higher reserve margin increases.

And actually, these costs can be quite high. There is no cost impact estimate provided in the study, but if we were just to look at the costs of new entry from reference plans like a combined -- a combustion turbine, for example, we might be looking at costs on the order of a hundred thousand dollars per megawatt year and if we are looking at a cost increase at that level associated with, you know, roughly 2,000 megawatts overall, that the cost can be around hundreds of millions per year.

So this is something that's very important to quantify. We don't provide -- we are a think tank at the World Resources Institute so we don't provide recommendations but we want to make sure that this information is available for others to make those types of recommendations.

So just to look at some of the -- the drivers, the key drivers that produce this increase in the reserve margin and thus increase in potential ratepayers' responsibility, one of the key drivers is the winter outage rates and the winter risk. So when Astrapé did the modeling of the required reserve margin increase due to winter outage rates and risk, they looked at historic rates. These historic rates do not take into account the -- the improvements to the generator fleet that is required by this Commission and that is required by NERC or recommended by NERC and that are becoming some of the best practices in the region. So by implementing some of these improvements, we can reduce the amount of reserve margin increase and thus ratepayer impact.

In addition, improved short-term

forecasting can help us better understand how to schedule maintenance, essentially, planned outages, so that they're not happening during these winter peaks. That will also help us reduce the ratepayers impacts due to reserve margin increases. A better understanding of the short term forecast can also help us implement additional demand response. We can convey some of that information to -- to new load. And I do want to note that much of the new load that's coming online could be flexible in response to prices, especially if they're given timely information and incentives to do so.

The other key driver to the reserve margin increase is the limited resource adequacy sharing between neighbors. So the assumption in the Astrapé study is that each of their -- each of Duke's neighbors are sitting at the bare minimum in terms of resources. So they're assumed to be at the dotted lines, just having enough resources to meet the one in ten loss of load expectation criterion, where historically, all of the neighbors have been -- have been long on resource adequacy. So the solid lines represent where they have been at in terms of the resources they have on this system.

So these resources are available to -- to share as part of the modeling and -- and including that information in the modeling would be a little bit more consistent with the -- with the using historic data if that -- if that's the approach that is the best. But we want to make sure that we are using consistent data across a different -- across a different assumptions and drivers. And if we are looking at historic data for outages, looking at historic data for the amount of resources your neighbors have on the system would be helpful too.

And just to note that the other assumptions around the scenarios looking at the, you know, whether or not Duke Energy Progress/Duke Energy Carolinas are isolated from each other or isolated as a system from their neighbors, some of these scenarios don't reflect what -- what currently happens. The base case is the scenario in the Astrapé study that is the closest to the current status quo. And there weren't any -- there wasn't any modeling of additional resource adequacy sharing that could happen.

The -- however, it is -- it is useful to note just some of the savings, the resource adequacy savings, that can happen from increased sharing with neighbors. So, you know, from the most conservative options, scenarios, for example, DEP was sitting at a target of 26 percent, DEC at 28 percent. And that -- those numbers were able to come down with additional resource adequacy sharing to 22 percent. So remember, again, that each percentage point can be in the tens of millions of dollars per year.

So one final note before I turn it over to Mr. Urlaub is that we recognize that you don't have to be at an RTO to share resources with your neighbors and to make sure that everyone's on equal footing when we are thinking about how these resources are shared. So in the west with vertically integrated non-RTO utilities in the west, there is the western resource adequacy program, and that program has brought the winter reserve margin down to 13 to 19 percent to meet the one in ten loss of load expectation criterion.

So you can see that you can meet the

same level of reliability, share resources without being in an RTO, and make sure that ratepayers are not footing as large of an impact. So with that, I'd like to turn it over to Mr. Urlaub.

MR. URLAUB: Thank you, Dr. Chen. Good afternoon, Commissioners. Unfortunately, Expert Witness Brent Alderfer could not join us today so I'll be presenting on his behalf as well. Thank you for this opportunity to present. I'll dive right in.

So please join me on the way-back machine for just a minute and we will go to 2004. Compared to 2004, Duke is proposing a nineteen times increase in electricity generated from natural gas. In 2004, it was well-established by Progress Energy that it was too expensive to use natural gas to generate more than two percent of energy. The strategy was to get the the highest value out of gas while minimizing exposure to cost risk.

A lot has happened in the past 20 years. The natural gas network was not built to fuel electric power generation, yet the expansion of natural gas power generation fleet by

Duke and other southeast utilities has reached unprecedented levels. Between Duke's 2022 carbon plan -- so now we are coming back to present -- and the proposed P3 fall base portfolio proposed in Duke's CPIRP supplemental analysis, Duke has nearly tripled its proposed gas capacity additions while increasing the portion of energy generated from natural gas to just under 40 percent, as shown on the left- and right-hand-side of this slide.

Duke's supplemental analysis proposes nearly all of the 8,925 megawatts of natural gas capacity additions will be complete by 2033. Yet just after 2033, as you can also see in the chart, Duke begins to steadily decrease natural gas's contribution to Duke's proposed energy mix until it reaches zero around 2050. Adding gas plants just one to three years before they are going to be used less and then not at all makes Dr. Chen's testimony examining reserve margin that much more salient, as some of this gas capacity is in support of a higher reserve margin.

Even greater than the stranded cost risk is the price in supply risk from Duke's near and mid -- mid-term dependance on natural gas. We show in our testimony that domestic demand is increasing as more utilities add gas combined cycle combustion turbine capacity. And as a result, we think gas demand and prices will be higher than projected in Duke's base natural gas price forecast which is presented here in the chart.

Our analysis of the EnCompass production cost modeling runs finds that if Duke builds to the proposed P3 fall base portfolio but then gas prices turn out to track closer to the high gas price forecast, Duke could potentially spend 67 percent more on gas fuel than assumed. Ratepayers will bear this full increase through the fuel rider and the present value revenue requirement of this large difference in fuel costs can be found in our confidential testimony.

The era of flat electricity demand is over. We've been talking about that today. We are going to have to increase our power production. We've been talking about that today. But unfortunately, the era of gas fuel price stability also appears to be over. And we have returned to an inherently volatile natural gas market, which is why I asked you to join me for a moment in the way-back machine to 2004.

You'll note in this chart that I am referring to the period of relatively low and more stable gas prices that started around 2010 and ended around 2020. We just highlighted the unprecedented levels of proposed domestic gas -- domestic gas use to meet this demand. And so now, let's step back and look at the global market demand.

EIA found that as the domestic LNG market has become increasingly connected to the global LNG market, the price of gas is going to increase for domestic consumers. This connectedness not only drives price increases, it also increases our exposure to global price volatility.

For example, the natural gas price run-up due to the Russian invasion of Ukraine cost Duke customers multiple billions in additional unplanned rate increases that Duke did not successfully hedge against. Specifically, Duke's 2020 IRP projected that gas prices would be $2 per

MMBTU in 2020 and $2.75 in 2021 and around $2.50 in 2022. A confidential analysis of the -- well, sorry. We can see in the historic chart that gas prices actually rose to over $8 in 2022. A confidential analysis of the multiple billions in additional fuel costs that resulted and were borne by Duke customers can be found in our testimony.

Duke's price forecast unfortunately left out the billions in additional costs that resulted from a global volatility event which Duke and its ratepayers are now exposed to, and this volatility was additional on top of their base price forecasts. And ratepayers cannot handle multiple surprise billions in additional volatility costs every several years occurring on top of Duke's forward price projections.

LNG export capacity is expected to more than triple by the early 2030s and become our nation's largest domestic end-use sector. So this is why I was just talking about LNG in the last slide. This is in response to rising global demand for natural gas, which the EIA projects is going to rise 152 percent by 2050 while domestic gas production will increase only 15 percent.

The current projection is primarily driven by rising U.S. exports to Asia and Europe. And a separate and additional source of price and volatility risk is North Carolina's lack of in-state gas supply and infrastructure. So said another way, Duke's dependance on interregional pipelines and infrastructure for fuel supply.

Duke provided detailed explanations in both its 2022 carbon plan and the 2023 CPIRP and supplemental analysis stating that existing supply options are insufficient to fuel the current fleet as well as the proposed capacity additions. In this CPIRP, Duke plans to burn diesel and coal at certain times of the year due to this insufficient natural gas supply.

Today, we have covered three risk factors that will make gas prices higher and more volatile but Duke has discounted in its planning -- in its planning: Market fundamentals, exposure to greater regional and global volatility, and the supply risk from depending on interregional pipelines that do not exist and that Duke notes, that will still likely be insufficient without further investment in gas infrastructure and storage, investments that are not included in this plan.

These regional and global risks are layered. They interact in ways that compound price risk and they are outside of Duke's control and will be borne by Duke's ratepayers.

COMMISSIONER KEMERAIT: So let me interrupt you. The 15-minute time limit has been up for a couple of minutes now. I will give you just very brief leeway, because I do know that you want to talk about how to reduce risk and reliability concerns. So if you could do that in a minute or less, that would be appreciated.

MR. URLAUB: It is the last slide, so thank you for the leniency. As the Commission considers these risks to ratepayers at this unprecedented level of reliance on natural gas and the gas system, we would like to highlight three near-term options from a long list of options that are available that would help systemically reduce these gas risks and reliabilities that are outside of Duke's control.

Duke can reduce price variance by adopting portfolios that rely less on natural gas, first and foremost. Duke could reduce price and reliability risk by producing more fuel-free resources, building out its transmission system and other grid enhancing measures, and offering additional efficiency and demand responses as we've heard from a number of witnesses today. And Duke should use its high gas price forecast instead of the base price forecast.

When 40 percent of your generation depends on a resource that presents the greatest risk of price increase and extreme recurring price volatility out of your entire portfolio, it's better to be too high and wrong than too low and wrong.

So our testimony recommends, with explanation, that Duke accurately price volatility and begin including the cost of fuel volatility and measures to mitigate that volatility into its plans. And our confidential analysis indicates the P3 fall base would not be the least-cost portfolio. Instead, a portfolio that relies less on gas and more on fuel-free resources will be lower cost and reduce risk.

COMMISSIONER KEMERAIT: Thank you,

both, for your presentations. Let me check to see if there's any clarifying questions.

(No response.)

COMMISSIONER KEMERAIT: Okay. I see no clarifying questions so you may be excused.

MR. URLAUB: Thank you.

COMMISSIONER KEMERAIT: And our final party is Appalachian Voices.

MS. BONVECCHIO: Thank you, Presiding Commissioner Kemerait. Appalachian Voices calls Evan Hansen to the stand.

COMMISSIONER KEMERAIT: Good afternoon. You may begin whenever you're ready.

MR. HANSEN: Thank you. My name is Evan Hansen. I'm the founding principal of Downstream Strategies which is a consulting company that works on energy and water science and policy projects. I appreciate this opportunity to present to the Commission.

My testimony will cover two types of risks. The first type of risk are regulatory risks, specifically related to the Clean Air Act Section 111 Rule. And the second type of risk is related to the natural gas market, and more specifically, related to the natural gas demand, supply and volatility.

So I'll start with the regulatory risks. And with the Clean Air Act Section 111 Rule, I'll start with the impacts on new natural gas-fired power plants. And this was mentioned particularly by the Public Staff witnesses at the start of this hearing today, that this rule includes three categories of new natural gas-fired power plants, base load, intermediate load and low load. And that base load category is important. Those are the plants that will run more than 40 percent of the time and they have a requirement to implement carbon capture and storage at a rate of 90 percent by 2032.

Now it's important to state at the start that the Companies' model of the P3 fall base portfolio did not account for this rule. While they acknowledged the proposed rule in their documents and testimony, the core portfolio, the core model run did not account for the reduction in generation at the CC plants or the new generation that's going to be needed to make up for that reduction in generation in order to meet the requirements of the new 111 Rule. And their model also did not incorporate the increased costs.

According to the final rule, the Companies really have two choices for compliance. They could run them as base load plants, but that would require carbon capture and sequestration. And according to the Companies, that's not going to be feasible. So with that off the table, the Companies discussed in their filing running their new CC plants less often. Again, if they're run at a lower capacity factor, then they would not be classified as a base load plant and CCS would no longer be required.

But it's important to note that in the Companies' discussion, they were looking at the draft rule, not the final rule. And the draft rule had a different threshold for base load plants. That threshold was a 50 percent capacity factor whereas the the final rule has a 40 percent capacity factor. So according to the filings that the Company made, they were already talking about only running their CC plants half the time at a 50 percent capacity factor. But reducing it by ten percent, that's equivalent to those plants sitting idle for another 37 days per year, which has implications for the stranded asset risk that has been mentioned by other witnesses.

If these new CC plants are run less often, that will increase costs. There will be a higher cost per kilowatt hour at the new natural gas plants, but there also will be additional generation needed at other plants to make up for that shortfall. And while the Companies don't have an estimate of the increased cost related to the final rule, they did have a $3.6 billion estimate for an increase in the present value of revenue requirements relative to the P3 base portfolio.

Now the actual increase would be higher for a couple reasons. One is that difference in capacity factor of threshold that I mentioned where the proposed ruling was 50 percent but the final rule used 40 percent. But also, they compared it to the P3 portfolio and not the P3 fall base portfolio, which has a higher assumption for the load forecast.

The other portion of the Section 111

Rule that's important for this proceeding is related to existing coal-fired power plants. And the rule has increasingly stringent requirements for plants that are going to continue to operate for longer periods of time. And what I've found by looking at the model results from the Companies is that according to the P3 fall base portfolio model, the Roxboro 2 and 3 Units, they don't comply with the final rule because they showed generation from coal through 2033. But according to the rule, they would need to show co-firing of natural gas at that point because they would be classified as medium term units. But the model runs do not show that co-firing.

Finally, related to the 111 Rule, I ask the question: Can the Companies delay closure of their existing coal-fired power plants to generate the additional electricity that will be required due to running the CCs less often? And what I found was no, certainly not past 2038, because running a coal plant past that date would require carbon capture and sequestration, which the Companies deemed to be infeasible, but probably not even past 2031, because if they were to do that, they would need to co-fire 40 percent natural gas and even if technically feasible, that would be unlikely to be economically feasible since that plant would need to be shut down soon.

So in summary, the P3 fall base portfolio does not comply with the rule. They have not yet analyzed the impacts of the running their new combined cycle plants at 40 percent. The Roxboro 2 and 3 coal-fired units don't show co-firing with natural gas. And very importantly, the costs associated with the compliance in the Companies' submissions did not include compliance with the final rule. So I recommend to the Commission that you require the Companies to develop portfolios that do comply with the rule and require them to assess the impacts on ratepayers.

And now I'd like to move on to the second part of my testimony which looks at other risks related to the natural gas market.

COMMISSIONER KEMERAIT: So I'll go ahead and give you information about the time. It looks like you have about three more minutes for the second portion of your presentation.

MR. HANSEN: Thank you. The -- the P3 fall base portfolio requires much more natural gas, more than doubling of the natural gas requirement from 2023 to 2030, which is when natural gas demand peaks. And it's important to look at that demand in the context of other sectors and other states. Other utilities are also considering significant build-outs of natural gas plants. There's increases in other sectors and as the previous witness mentioned, competition from LNG exports --

COMMISSIONER KEMERAIT: Mr. Hansen, let me correct that. You had seven more minutes as opposed to three minutes. I don't want you to rush since I miscalculated.

MR. HANSEN: Okay. Thank you for that.

So in addition to risks related to natural gas demand, there's also risks related to natural gas supply. And those are very closely related.

Now, the first thing to say about natural gas supply is that no natural gas is produced here in North Carolina, and all of the natural gas comes through the Transco Pipeline, as you're aware, and the Transco Pipeline is fully subscribed.

Now, there was big news last week. The Mountain Valley Pipeline was approved to start sending gas toward this way. It was big news in West Virginia where I come from since that pipeline is coming from West Virginia. But it's important to recognize that even though the Mountain Valley Pipeline is in operation now, there are other pipeline projects that must be completed in order to access that gas and those include the Mountain Valley Pipeline South Gate Extension, the Southeast Supply Enhancement Project, and the Dominion T15 Reliability Project.

And some of these pipeline projects have to be completed to bring more gas into the region, but others are required to fuel specific plants. And what's really important to note is that the inservice dates for these projects are beyond the Companies' control and that many pipeline projects in recent years in the eastern United States have been cancelled or, like the Mountain Valley Pipeline, significantly delayed.

Natural gas demand and natural gas

supply can lead to volatility when they're out of balance. And the Commission is familiar with this because of the rate increases that the Commission approved in 2023 that were related, at least in part, to volatility in natural gas prices due to Winter Storm Elliot and geopolitical events that, again, were outside the Companies' control. And these were significant increases, hundreds of millions of dollars.

As their previous witness mentioned, the P3 fall base portfolio makes the Companies even more susceptible to volatility. Using the Companies' own numbers in 2030 when natural gas use is projected to peak, the Companies project their delivery costs of natural gas to be about $2.5 billion, and that's at $4.21. If, for example, the price were $6 instead of $4.21, that cost would increase to 3.6 billion. That's an increase of $1.1 billion. Basically, for every penny increase in the price of natural gas, the cost would increase by about $6 million. And that's why it's so important to consider volatility in your deliberations.

This chart from my testimony shows how

volatile natural gas prices have been at the Henry Hub, and I divided this into two time periods starting in 2010 when the market shifted with the advent of hydraulic fracturing. So we had a lot more natural gas supply. But the green area starts in 2016, which is when the market was exposed to LNG exports. And what we found is that there was considerably more volatility since 2016. There was an upward trend in prices you see around 2022, the impacts of geopolitical events, Winter Storm Elliot.

But another thing to note is the outliers. There are some outliers, those dots that are up very high showing how volatile prices can be. And that's at the Henry Hub. The next slide shows the difference in the price from Transco's own five to the Henry Hub and North Carolina is in Transco's own five. And what you can see is that there are periodic but more frequent episodes or events where the price paid in Transco's own five is significantly higher than the price paid at Henry Hub, sometimes ten, twenty, over a hundred dollars higher than the Henry Hub price.

So the volatility at Transco's own five in the price of natural gas is something that definitely needs to be considered by the Commission. And that volatility is impacted by several factors. It's the number and severity of extreme weather events. It's impacted by geopolitical events. It's impacted by exposure of the domestic market to LNG exports. And again, these factors are beyond the Companies' control.

So to summarize my testimony about the other risks, natural gas demand is increasing in other sectors and in other nearby states. So the projected natural gas demand increase from the Companies here in North Carolina needs to account for that, because they're competing for the same natural gas coming through the same pipes -- same pipelines, and that has potential impacts on cost. And despite the completion of the Mountain Valley Pipeline, other pipeline projects must be completed to supply the required gas. In fact, the Mountain Valley Pipeline gas cannot be used here in North Carolina without completion of the South Gate project to bring that here -- that gas here into North Carolina. Natural gas price volatility has been increasing. And again, these risks are beyond the Companies' control.

So my recommendations to the Commission regarding other risks are to account for these risks when you make a decision in this proceeding and compare the risks in the P3 fall base portfolio to the risks in any alternative portfolios that may be presented by other intervenors. But thank you for this opportunity to present. Happy to take questions.

COMMISSIONER KEMERAIT: Thank you for your presentation. Let me see if there's any questions.

(No response.)

COMMISSIONER KEMERAIT: Seeing none, we appreciate your presentation and you may step down.

So we have come to the end of presentations by the intervenors. So with that, I want to thank everyone for their very good and informative presentations. We will conclude this Technical Conference. We will go off the record.

We will be coming back on the record in five minutes to begin the next Technical

Conference. So at 2:15, we will begin the Solar
Procurement Technical Conference. Thank you.

(The technical conference was adjourned at 2:12 p.m. on Wednesday, June 17, 2024.)

C E R T I F I C A T E

I, Christina Kornikh, do hereby certify that the Proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the Proceedings set forth herein, and the foregoing pages are a true and correct transcription to the best of my ability.

Christina Kornikh,

Stenographic Shorthand Reporter