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BEFORE: Commissioner Daniel G. Clodfelter, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Lyons Gray

Commissioner Kimberly W. Duffley

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:

Technical Conference

2020 Biennial Integrated Resource Plan Reports

and Related 2020 REPS Compliance Plans by Duke Energy

Carolinas and Duke Energy Progress

VOLUME: 4

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

FOR DUKE ENERGY PROGRESS, LLC AND
DUKE ENERGY CAROLINAS, LLC:
Jack Jirak, Esq.
Deputy General Counsel
Duke Energy Corporation
410 South Wilmington Street
Raleigh, North Carolina 27601

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

FOR VIRGINIA ELECTRIC AND POWER COMPANY d/b/a
DOMINION ENERGY NORTH CAROLINA:
Andrea Kells, Esq.
McGuireWoods LLP
501 Fayetteville Street
Raleigh, North Carolina 27601

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

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

FOR NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION:
Benjamin Smith, Esq.
Regulatory Counsel
4800 Six Forks Road, Suite 300
Raleigh, North Carolina 27609

FOR SOUTHERN ALLIANCE FOR CLEAN ENERGY, THE SIERRA CLUB, AND NATURAL RESOURCES DEFENSE COUNCIL:
Gudrun Thompson, Esq.
Senior Attorney
Nicholas Jimenez, Esq.
Staff Attorney
Southern Environmental Law Center
601 West Rosemary Street, Suite 220
Chapel Hill, North Carolina 27516

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

FOR CAROLINA UTILITY CUSTOMERS ASSOCIATION AND
TECH CUSTOMERS:
Craig D. Schauer, Esq.
Marcus Trathen, Esq.
Brooks Pierce
150 Fayetteville Street, Suite 1700
Raleigh, North Carolina 27601

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

FOR NC WARN AND THE CENTER FOR BIOLOGICAL DIVERSITY:
Matthew D. Quinn, Esq.
Lewis & Roberts, PLLC
3700 Glenwood Avenue, Suite 410
Raleigh, North Carolina 27612

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

FOR THE USING AND CONSUMING PUBLIC AND THE STATE OF NORTH CAROLINA AND ITS CITIZENS:

Margaret A. Force, Esq.
Special Deputy Attorney General
Teresa L. Townsend, Esq.
Special Deputy Attorney General
North Carolina Department of Justice
Post Office Box 629
Raleigh, North Carolina 27602

FOR THE USING AND CONSUMING PUBLIC:

Lucy E. Edmondson, Esq.
Layla Cummings, Esq.
Robert B. Josey, 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:

Duke:

Coal Retirements Panel:

Glen Snider Michael Quinto

Dan Donochod Robert McMurry

All-Source Procurement Panel:

Glen Snider George Brown

Jim Northrup Bill Quaintance

Grid/Transmission Panel:

Glen Snider Bill Quaintance

Sammy Roberts Nick Wintermantel

Mark Byrd

Southern Alliance for Clean Energy, Natural Resources Defense Council, the Sierra Club, Carolinas Clean Energy Business Association, and the North Carolina Sustainable Energy Association:

Rachel Wilson Jeremy Fisher

John Wilson Steven Levitas

Jay Caspary

Attorney General's Office:

Edward Burgess Maria Roumpani

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

Public Staff:

Dustin Metz Jeff Thomas

Bob Hinton

P R O C E E D I N G S

COMMISSIONER CLODFELTER: Good morning, everyone, and welcome back to our recessed session here. We're gonna try to close it out this morning with the presentations of the participants on transmission issues. Let me say, by way of a couple of preliminaries, we have until noon today. We don't have a lot of leeway beyond that, so we will just need to deal with that as we have to.

We're -- this is not a general open-ended forum on transmission issues. We're really wanting to focus this morning on the grid impacts of the different resource portfolios that are set forth in the 2020 IRPs of Duke Energy Progress and Duke Energy Carolinas. So if we can try to keep our focus and our conversation on that, that would probably help us with the time issue.

Having said that, if I recall correctly, Mr. Breitschwerdt, you have the baton on this issue; am I correct?

MR. JIRAK: Commissioner Clodfelter, that's correct, and if I may just lay the foundation a bit for the transmission presentation, then I'm gonna hand the reins off to Brett, if that's all right with you.

CHAIR MITCHELL: You may do so.

MR. JIRAK: So just to kick things off, Commissioner Clodfelter, we wanted to just acknowledge the fact of the energy legislation that's obviously been announced, and recognize that, sort of, unique nature of that, in terms of the fact that the administration and Senate/House leadership having reached agreement on a comprehensive energy framework going forward, and we know the Commission is closely reviewing that, as we are as well. And if it's ultimately enacted, we certainly recognize that this will impact the short- and long-term planning processes under the IRP. And we, obviously, just want to be clear that we are very encouraged by the development. It's a very important development in the state, in terms of energy policy, and we fully support the goals and framework set forth in that legislation.

And I think our presentation today dovetails nicely with that, because the energy legislation obviously contemplates a kind of all-of-the-above approach to achieving carbon reduction consistent with least-cost planning principles and ensuring continued reliability. So we think talking about grid is very timely, because that's going to be part of the puzzle, we believe, and we think some -- even this morning you will hear some of those themes around how transmission and grid reliability issues would be critical to achieving those legislative objectives, again, if they are enacted.

So we just wanted to acknowledge that, and hopefully our presentation will touch on some of these really critical issues. So with that being said, I want to turn the reins over to Brett who will lead us into the panel.

COMMISSIONER CLODFELTER: Very good. Thank you.

MR. BREITSCHWERDT: Good morning, Commissioner Clodfelter, Commissioners. Again, Brett Breitschwerdt on behalf of Duke Energy. The panel this morning, the grid panel, will be led by Mr. Sammy Roberts, and with Mr. Roberts will be Mr. Mark Byrd who is pinch-hitting for Bill Quaintance, who is out of the office this week and not available to participate; Mr. Nick Wintermantel with Astrape Consulting, who was responsible for the resource adequacy study that the Companies filed, the 2020 IRPs; as well as Mr. Snider, who just can't seem to get enough of presenting to you-all on IRP issues. He's not going to be presenting slides, but definitely had a key role in helping to utilize the information that the transmission experts for the Companies developed in shaping the 2020 IRP.

So, with that, I'm gonna share the presentation, and we'll turn it over to Mr. Roberts.

COMMISSIONER CLODFELTER: All right. Thank you all.

MR. ROBERTS: All right. Thank you, Brett. You can go to the next slide. Good morning, Commissioners and Chair Mitchell. I'm Sammy Roberts with Duke Energy, and today in the grid impact's presentation we will discuss how we addressed incorporating grid impacts into the 2020 IRPs. We will also discuss evaluating the way in which resource planning and transmission planning intersect for addressing resource adequacy, coal retirements, and the integration of incremental resources. Today we will be presenting on three topics.

First, Nick Wintermantel with Astrape Consulting will present our resource adequacy, reserve margin, and the risk of relying on significant incremental import capability for future resource planning. Second, I will present on the role of transmission planning to facilitating carbon reduction targets and to support future resource planning, in addition to describing the growing complexity of transmission planning. Third, Mark Byrd, manager II in engineering with Duke Energy, will discuss the North Carolina Transmission Planning Collaborative studies and how they could inform development of IRPs. Lastly, I will wrap up the presentation with key takeaways for informing the 2022 IRPs.

So now I will turn the presentation over to Nick Wintermantel.

MR. WINTERMANTEL: Thanks, Mr. Roberts. Good morning, Chair Mitchell. Good morning, Commissioners. I appreciate the opportunity to be here. We could go to the next slide, Brett, if that's okay.

As Mr. Roberts said, I'm

Nick Wintermantel, a principal at Astrape Consulting. I've been doing resource -- adequacy resource planning work for the last 20 years. We do lots of resource adequacy studies around the country and even some internationally using our industry-accepted server model. So we have done work from California to Canada to Texas to SPP to a lot of the utilities in the Southeast, and today I really just want to talk about how the transmission assumptions and -- were included in the study and how they impacted the results. Next slide.

Just briefly -- and overall, my remarks are fairly short. I have a pretty short deck, but just kind of level-setting what is resource adequacy, what is a resource adequacy study. I want to spend just one or two minutes talking through that.

So what is resource adequacy? It's the ability of supply-side and demand-side resources to meet the aggregate electrical demand. When we talk about resource adequacy, though, we're really focused on peak periods, extreme-weather periods. Do we have enough capacity on the ground to meet that peak load? We are not talking about distribution customers' outages or outages caused by storms that are much more frequent. When we talk about resource adequacy, you guys have probably heard, are familiar with LOLE, loss of load expectation. The industry standard is 1 day in 10 years. So, essentially, what we're trying to do in resource adequacy is make sure we have a high-enough reserve margin so that our system -- so that Duke's system would only shed load 1 day in 10 years. When we define reserve margin, that's just our install capacity, minus our peak 50/50 projected load, divided by peak load.

Ultimately, in resource adequacy, customers, they are going to expect the lights to be on all hours of the year, and it's even more critical during those extreme weather periods. For the companies, that really has shifted to being that extreme cold winter morning. That's where the resource adequacy risk lies for the companies.

So why do we need a reserve margin? Again, I've hit on a couple of times, extreme weather conditions. Load can be much higher than forecasted during these extreme weather conditions. We could have poor unit performance. So whether it's a dispatchable generation or intermittent resource, we could potentially have poor performance that day, and then we could also miss our load forecast. Load may grow faster than we expect. So combinations of these things are what occur when we have these unreliability events. Next slide.

Now, just jumping right into the transmission assumptions that are in the study. The model -- it's a pipe-and-bubble representation. So here on the right you can see the transmission network that was modeled. We have the Companies, DEC and DEP, in blue, and then we model one tie away. And the objective is to try to capture what is the weather diversity and generator-outage diversity among these regions.

Essentially, what we're talking about, though, is non-firm imports and capabilities. So what can we expect on that cold winter day? We do extensive modeling, so there is roughly 200,000 megawatts of generation modeled in the network for these one tie away. So you can see we model all the way up to PJM, and then it into the Southeast.

One thing that we do see in all our modeling -- we have been doing, I guess, the studies for two -- we've had two or three iterations of this resource adequacy study for the Companies, but what we see is in the Southeast it's typically capacity-constrained, not transmission-constrained. Meaning, if we increase transmission, we are likely still not going to be able to get more non-firm imports, because, essentially, when it's cold in Duke, it's also cold in TVA, Southern, and the Carolinas. And so it's typically more capacity constrained. In PJM, there is a little bit more weather diversity, and so, more often, you can have some transmission constraints up there.

When we think about non-firm imports, though, they are certainly more certain than firm contracts, right? And the companies have no control what TVA and PJM do in their planning processes. So it is highly uncertain what will be there on that cold morning. We have historical data that we can look at, we can talk to operators to get their comfort level, but it is an unknown. And, kind of, really even further making that uncertain is this transition that not only the Companies are going through -- it's transition from retiring base-load fossil fuels, adding intermittent and energy-limited resources such as solar, wind, and storage -- but that's occurring everywhere.

And, you know, one thing that we note in Dominion -- Dominion Energy Virginia, which would be located PJM south in our topology here, is, just recently, to meet their Virginia Clean Economy Act, they're showing substantial additions of solar, wind, and battery storage. With these additions, they are projecting that they are actually winter-peaking now, that they are expecting to rely more on imports during the winter.

So it's this game of -- as I think was Mr. Snider had said, it's a game of musical chairs, right? You are all maybe hoping that there is gonna be this capacity there, but maybe somebody else needs it. So it's very uncertain, so we want to be careful how we model these things. Next slide.

So the previous slide was, kind of, the assumptions that go into the model, and then here's, kind of, the results of what that looks like. So if I focus on the table here on the left, this is winter reserve margin to meet this 1-day-in-10-year standard. If we assume that DEC and DEP are islands -- so they have no interconnections, you get none of this weather diversity benefit with your neighbors -- essentially DEC would need to carry a 22-and-a-half percent reserve margin in the winter, and DEP would need 25-and-a-half percent.

And when we do incorporate the neighbor assistance and we allow for sharing, subject to those transmission constraints, the recommended winter reserve margin is reduced to 17 percent, which is the Company's recommendation.

So, essentially, the study is already taking into account a 5 to 8 percent reduction in reserve margin due to this reliance on non-firm imports, this weather diversity we have with your neighbors. We recognize the interconnection benefits there, and we are getting that reduction in our reserve margin. Ultimately, on that cold winter morning, that represents approximately 2,000 megawatts that we expect to be able to go get a day ahead or during real time. And, Commission, that's a substantial amount of capacity that we're already relying on.

From Astrape's perspective, even if the import capability was increased, we would expect that any opportunities on the other side of that transmission line would need to be firm contracts. We wouldn't want to say that we can reduce our 17 percent firm number -- firm reserve margin in order to rely more on non-firm imports.

We can kind of see in the chart on the right, we've got the island levels, the 25 and 22 percent, but we would want to always hold that 17 percent in some type of firm contract, whether that's utility-owned or through PPAs or even purchased from external, but we would want that firmed up.

Just in our studies across the industry, it is certainly not uncommon for there to be some type of limit put on our reliance on non-firm imports. A lot of utilities, though, these studies are confidential, so it's difficult to see that information, but RTO studies are very available, and if you go look around and look at what MISO or

PJM are doing, you know, they are more in the 2-to-3 percent on what they are relying on non-firm imports, and SPP actually relies on zero. So we are already being very aggressive in the study when it comes to non-firm imports. Next slide.

So this is my last slide. Just the takeaways. Again, based on the study, we recommend this 17 percent winter reserve margin, and already assumes a large amount of non-import capability. We think there is substantial risk in increasing our reliance on non-firm imports. Again, we have no control of what surrounding neighbors are doing in their plans, and they are certainly not planning for Duke's load when they are doing their resource planning.

Another point I would make is the 17 percent reserve margin being held by Duke, it is lower than many of the utilities in the Southeast. I think it is largely driven by the interconnections that we're already taking advantage of. Duke also had relatively good generator performance as well, so I think that's a couple of reasons. I mean, if you look around at Southern and TVA, their recommended reserve margins are in the 25 percent range.

And then just lastly, I would say, during this transition, it's an exciting time for the industry, right? We are retiring a significant amount of fossil fuel generation, adding lots of cleaner renewable intermittent energy. It just is not the time to take this additional risk and say, look, let's build transmission and go rely on non-firm imports and let our neighbors take care of us. We don't think it's the time to be doing that. And even with the 17 percent reserve margin, going into the winter, it's certainly not a guarantee that we won't have an event. I mean, we're planning to 1 day in 10 years. In that extreme cold day where maybe market imports are not there, that would be the type of day where we will have an event. So I can't guarantee that, just because we carry the 17 percent, we won't ever have an event.

And with that, that is the end of my slides. I'll turn it back over to Mr. Roberts, who is gonna talk -- go more into the transmission planning side of things. Thank you.

MR. ROBERTS: All right. Thank you, Nick. And good morning, again, Commissioners and

Chair Mitchell. I'm Sammy Roberts, general manager for transmission planning and operations strategy. A little bit about my background. I have over 31 years experience working for Duke Energy and its predecessor companies, and the majority of my career has been in the system planning and operations area. And so I'm gonna present on the intersection of resource planning and transmission planning in relation to IRP considerations. Next slide.

So transmission planning functions, whether it's analyzing NERC transmission planning standard compliances with TPL-001, studying generator interconnection requests, studying new delivery-point loads or transmission service requests, it's obvious they've increased in volume and complexity over the last decade. And this complexity, in my view, will only increase with more incremental resources requesting interconnection to the Duke grid. It's already seen a lot of its capability utilized by currently interconnected resources.

A new part of this complexity is that storage would need to be studied, both discharging energy into the system and absorbing energy from the system.

Modeling will increase in complexity as we transition our analytical approach in ISOP to a more granular approach to try to further optimize the integrated resource and grid system, our future IRPs will most likely need to continue to look at alternate pathways of resources for achieving clean energy targets, and that will just add to the modeling complexity with grid resource interaction.

Lastly, as neighboring systems such as PJM South transform their resource mix, as Nick mentioned, power flows will change; and thus, transmission studies will need to ensure they encompass those realities to preserve power system reliability. Next slide.

On this slide, I would like to discuss how we estimated transmission network upgrade costs for the 2020 IRPs and associated incremental resources and replacement resources. First, generation replacing retired coal. If we locate that replacement generation at the Brownfield site, we can significantly reduce the transmission network upgrade cost; and thus, in the 2020 IRPs, it was considered to be insignificant. We also provided cost for network upgrades, such as static VAR compensators for voltage support, if the replacement resources were not located at the retired coal sites.

Second, for incremental resources interconnecting at other locations on the grid, we used system impact study results to determine a dollar-per-megawatt cost proxy for estimating upgrades for incremental IRP resources. I have an example of that on a future slide.

Third, for Oklahoma wind import, estimates were reflective of only Duke Energy Carolina's network upgrades for increasing the Southern Company to DEC interface capability needed to facilitate such import.

Fourth, for assessing the transmission infrastructure needs for offshore wind, we did utilize the 2012 North Carolina Transmission Planning Collaborative wind study, but we applied updated cost assumptions for the transmission upgrades identified in the study.

Lastly, looking at substantial increases in import capability, that required significant new transmission infrastructure, both with transmission lines, transmission substations, and static VAR compensators, and the estimated cost of that infrastructure was between 8- and $10 billion for increasing import capability by 10 gigawatts. Next slide.

So, in this slide, the table shows the DEC/DEP portfolio table from the 2020 IRPs. In looking at this slide, I want to highlight the vast amount of incremental resources represented in these portfolios. These portfolios represent up to 4 and a half to 12 gigawatts of additional solar, up to 3 gigawatts of onshore wind, up to 2.6 gigawatts of offshore wind, up to 1.3 gigawatts of small modular reactor, 1 to 7.4 gigawatts of storage, and 0 to 9.6 gigawatts of gas generation, all while retiring and replacing potentially over 9 gigawatts of coal plants.

Most of these incremental resources, if not connected to the same point of interconnection as retirement generation, could require significant transmission network upgrades, since we're running out of transmission capability for interconnecting additional resources. Next slide.

So, in this map, this is the EIA map of the North Carolina grid and the interconnected utility scale generators. The yellow circles are solar, the blue is natural gas, dark blue is hydro, purple is nuclear, and black with the white triangle is coal.

So what does the grid do associated with all these resources? The grid reliably moves generated megawatts to our load centers. As we have integrated a significant amount of distributed energy resources over the last decade, you can see we now have multiple generators injecting at multiple points on the grid.

One thing I would like to point out is that, even though the solar looks evenly disbursed on this map, especially in Eastern North Carolina, most of the larger transmission solar-connected facilities are located in Southeastern North Carolina, and that plays into the evolution of more transmission constraints that we're seeing on the grid.

So transmission planning, when they study these interconnections, they have to make sure that each resource can deliver its full output reliably to the grid conforming to their capabilities.

Next, I would like to point out the locations of our coal plants that are highlighted with red boxes. So first we have Roxboro and Mayo, a little over 31 megawatts, located north of Raleigh; then we have Belews Creek 1 and 2, about 2,200 megawatts, located just north of the Triad area: Greensboro, High Point, Winston-Salem; then we have Marshall plant, a little over 2,000 megawatts, north of Charlotte; Allen plant, 1,100 megawatts, south of Charlotte; and then in our Cliffside plant, 1,400 megawatts, near Gastonia, west of Charlotte. So these plants represent almost 10 gigawatts of capacity on the DEC and DEP systems and are located in our largest load centers, as mentioned.

Once again, if we don't replace the retired generation on site, and those replacement megawatts have to flow across the grid from the remote replacement resources to the load centers, a lot of transmission network upgrades will be needed to reliably change -- support the change in power plays. Next slide.

So, in this slide, I will further describe the -- how we came up with the dollar-per-megawatt proxy that we use for estimating incremental resource network upgrades.

On this slide, figure 1 shows an example of the resulting network upgrades determined to be needed to interconnect a 75-megawatt solar facility with our transmission system. So if we look at this diagram, you can see, in the blue clouds, we need a conductor upgrade of the 6.9-mile conductor, and we need two new line switches as network upgrades. And you can see, these facilities -- these -- this infrastructure is networked between substation A and substation B, which is further networked into the grid, thus the reason they are network upgrades.

By contrast, the interconnection facilities are located between the point of interconnection in a red box and the point of change in ownership in a red box. So those interconnection facilities are the ones that the solar facility must have in order to interconnect with our transmission system.

So how did we arrive at the

dollar-per-megawatts cost proxy for network upgrades? Once again, only what's in the blue cloud was estimated, because that's what the -- what goes into our revenue requirement, is the revenue upgrade. So how was the dollar-per-megawatt cost proxy for the network upgrades for incremental resources estimated? The table to the right shows over 30 queued generator interconnection requests that were studied for interconnecting with the DEC system. Some of the later queued requests had dependencies on prior requests, i.e., the same upgrades, so we did not double-count those in the dollar-per-megawatt cost proxy. In this example, the proxy cost used in the IRP for estimating network upgrades would be the $267 million network upgrade cost divided by 1,614 megawatts, or 16 and a half cents per watt. Next slide.

This red zone transmission constrained area map is located on our Oasis site, and these red zones have been used in the CPRE procurement program to identify areas where solar generators are not likely to be competitive. Locating any incremental resource in the red zone transmission constrained areas will likely incur expensive network upgrades for interconnection. Once again, we're essentially running out of places where grid capability is available that lends itself favorably to locating incremental resources such as solar and solar plus storage. Next slide.

So, in this slide, the highlighted areas on the background map reflect upgrades indicated by multiple generator interconnection request studies that we must resolve if we wish to connect 4 to 5 gigawatts or more of solar facilities. With respect to our transmission -- or transition, excuse me, to key reform and cluster studies, we believe the likelihood of funding such large network upgrades has been vastly improved by implementing cost sharing. However, while feasible, the current level of certainty, the queue reform will fund the largest upgrades, such as those reflected by the red, blue, and green highlighted constraints on the map is load.

Upgrades to enable future renewable interconnections may require new regulatory structures, as opposed to the current approach of upgrading in response to a filed interconnect request with a customer signing an interconnection agreement. If pursued in future proceedings, we would have to work through how costs are allocated if a proactive approach, based on something like levelized cost of transmission, is utilized to approve projects. In some areas, network upgrades are partially funded by the interconnection customer and partially funded by the transmission customers. However, the level of benefits are usually difficult to accurately determine, and, therefore, basic assumptions are used to split the obligation. A similar approach could be used to determine the proper assignment of benefits in the Carolinas when allocating costs of network upgrades. Next slide.

So with respect to looking at import capability with the 2020 IRPs, the Company conducted a high-level assessment to identify the number of transmission projects and estimated cost associated with increasing import capability into the DEC and DEP systems from all neighboring transmission regions as well as from offshore wind. The assessments considered the necessary new construction and upgrades needed to increase import capability by 5 and 10 gigawatts.

As indicated on the map to the right, 10 gigawatts of import capability would require the following new infrastructure on the DEC and DEP transmission systems: seven new 500 kV lines, two of which cross the Appalachian Mountains; four new 230 kV lines; three new 500/230 kV substations; four static VAR compensators; and several associated reconductor and lower-class voltage upgrades. The estimated costs for the associated transmission projects to increase import capability by 10 gigawatts is between 8- and $10 billion. Next slide.

So what about off-system capacity purchases? You've read in the record that all DEC and DEP -- sorry. Sorry about that. So you've read about, in the record, where DEC and DEP needs to do -- all DEC and DEP needs to do is increase import capability to lower our planning reserve margin. And I think Nick covered that pretty well. He stated in his presentation that resource adequacy and the resource adequacy study already accounts for nearly 2,000 megawatts of non-firm assistance during peak demand periods. Thus, it is recommended that any further off-system resource assistance needs to be in the form of firm capacity. This off-system capacity resource would need to be -- would need to have firm transmission service and a firm transmission service path to meet Duke Energy's designated network resource rules.

So three significant items need to occur -- and I have given an example here -- for making a capacity purchase from a generator in PJM and counting it as firm capacity for a DNR. First, we would need to contract with the resource under a firm capacity contract, and we would need to make that contract contingent on securing long-term firm transmission service. Second, we would need to request the long-term point-to-point transmission service in PJM, the red arrow, and firm point-to-point transmission service in PJM is around 63,000 per megawatt year, or 63 million per year for 1,000 megawatts. In addition, transmission studies may show that significant transmission network upgrades could be needed to facilitate this long-term point-to-point service in PJM, and Duke would have to pay that cost. Also, we would need to request network firm transmission service in CPLE, the yellow area, and that would need to be with respect to the PJM source per our designated resource rules. That would have to be studied with a transmission study to see if any network upgrades would be needed to make that service firm in CPLE. And lastly, any associated transmission upgrades have to be constructed and placed in service prior to the start of the contract for this capacity resource to count it as a firm capacity resource. Next slide.

So what are the key items to take away from this part of the presentation? As shown in the 2020 IRPs and will be shown in future IRPs, we'll have a significant amount of incremental resources being interconnected to the grid to replace the retired generation and to reduce CO_2 emissions. These new resources are incremental to the numerous resources already connected to the grid as depicted in the prior EIE map; and thus, grid planning is gonna get more complex, but this complexity will increase in the future as key determinants, such as megawatt size and location, variable and limited energy resources, and distributed connected resources result in changing power flows on the system.

This change in power flows will be exacerbated if we do not replace retiring generation with replacement generation connected to the same point of interconnection. With increasing interconnections, we're also realizing a decrease in capability of the grid to facilitate additional resource interconnections. If the future of incremental resource interconnections to our grid requires significant interconnections in primarily rural, high-radiance areas of our system, an alternative proactive approach to facilitating transmission network upgrades may be required.

Last, as Nick Wintermantel presented, just increasing import capability by itself will not improve reliability. There needs to be a firm capacity resource on the other side of the wire. Now I will turn the presentation over to Mark Byrd.

MR. BYRD: Good morning, Commissioners, Chair Mitchell. My name is Mark Byrd. I'm the -- I'm a manager II in the transmission planning and operations strategy organization. I'm gonna give an update on the North Carolina Transmission

Planning Collaborative studies.

A little background on myself. I have been with Duke Energy and its predecessors for over 40 years. A majority of that time, about 27 years, I have been in transmission planning roles with the Company -- with Duke Energy Progress, in particular. I have served on various NERC and SERC subcommittees during my time with the Company, and most recently I served as chairman of the North Carolina Transmission Planning Collaborative, the oversight steering committee. My term ended in June of this year in that role. So next slide, please.

First, I'm gonna give some background on what the North Carolina Transmission Planning Collaborative is. I'll start by saying it covers the transmission footprints of the Duke Energy Carolinas and the Duke Energy Progress systems. I'll say it was formed in 2005, and I have been participating ever since it was formed on the collaborative, and it -- let's see. It gives an opportunity for the load-serving entities in the Duke Energy transmission footprint, a chance to participate in the transmission planning process.

The participants are Duke Energy Carolinas, Duke Energy Progress, Electricities, and also the North Carolina Electric Membership Corporation.

So every year there is two sets of studies that the collaborative does. They do reliability studies annually, and they look at what's deemed to be a short-term or near-term look and a longer-term look. So they have models that are five-year-out cases of the transmission system and generation system and also a ten-year-out look at the system, the long-term look. Purpose of that is to combine the models and the plans of Duke Energy Carolinas and Duke Energy Progress, make sure they are compatible with each other and also look for additional plan -- transmission planning risk and possible needs.

The collaborative process also provides an opportunity for stakeholders to request additional studies. They generally are categorized into two types: economic studies or public-policy-type studies.

One thing I'll go ahead and state upfront is that the North Carolina Planning Collaborative does not -- is not able to perform official generator interconnection studies. The companies, DEC and DEP, have to follow the FERC large generator interconnection procedures and the North Carolina interconnection procedures. You know, there are formal rules for -- you know, for generators in the generation interconnection queues. The collaborative can perform generator studies, but they tend to be for information purposes. They do not -- they are not binding studies, because of, you know, all the different confidential information and other stuff that is involved with the generator interconnection queue. So I will come back to that point in a minute. Next slide, please.

So the recent studies that are pertinent. In 2020, there was -- a study report was released in January of this year for the 2020 through 2030 collaborative transmission plan. That report is available on the website for the collaborative, and it was looking -- we deemed that to be our reliability study. There was also a public policy request in 2020, and I'll describe that in more detail in just a moment. And then, in 2021, the collaborative is currently working on another -- a reliability study for the next 10 years, but also working on another public policy request, and we call it here the future resource scenario study, and I'll get into more detail on a slide in just a moment. Next slide, please.

So again, the base reliability study, the report that was released in January of this year, combines the latest models of DEC and DEP. It includes the latest transmission expansion plans of the two companies. The Company performs a base-line reliability analysis. It includes in the model any future generation that has signed interconnection agreements. It includes any generation retirements that are firm and that have been announced. It checks and confirms compliance to the NERC TPL-001 standard. I won't go into details, but, basically, it's -- there is a lot of different contingency outages that have to be checked to make sure they are not thermal violations of other lines or voltage violations on the system.

And then, in 2020, there was additional request. There was an economic study to look at a high-load growth scenario down in Union County and

Cabarrus County. And that was completed, and it's in the report that came out in January. And there was a public policy study request put in by the Southeast Wind Coalition in 2020, and I'll talk more about that in just a moment. Next slide, please.

Okay. So the public policy request that was submitted in 2020, that study was actually completed in June of this year, June 2021. It tested injections of offshore wind generation at numerous Duke Energy Progress substations near the coast. There actually was 32 different projection sites, substations that -- where offshore wind could be injected into the system, and it studied how much generation the system could handle there without upgrades or with small- and medium-level transmission upgrades. There was an assumption that 40 percent of the power being injected at these sites would stay within Duke Energy Progress' service area and 60 percent would be transferred to DEC -- the balancing area for DEC.

So, again, this study differed from prior studies in that we were really analyzing lots of different sites and different levels of megawatts at locations near the coast of Duke Energy Progress. And the results of that study that came out in June said the three most promising sites for larger amounts of offshore wind with -- that would be investigated for even more injections were New Bern, a new substation that could get created near Wilmington called Sutton North, and also the Greenville 230 kV substation.

The scope of this study requested to look at not only, you know, sites -- you know, how much wind generation could be added at various sites, but it also said also, what would it take to get up to 5,000 megawatts of offshore wind -- you know, what would be the best way and best locations to bring that into the system? So these three sites -- New Bern, Sutton North, and Greenville -- were examined to see what it would take to get larger amounts that included adding some new 500 kV lines to the system. So the report gives those details about these three sites. Okay. Next slide, please.

Okay. Now, bringing us to this year, 2021, there is a public policy request that was requested by the North Carolina Public Staff, and the goal was to look at a possible future resource scenario somewhat based on the 2020 DEC/DEP IRPs. And you can see here there was of a lot of assumptions made about retiring coal and additional renewables on the system. And not necessarily fitting any of the portfolios that were examined, but it is, you know, one study that looks at a combination of a lot of renewables and retirements all in one study.

So this study is underway, and one of the things that I think the collaborative has realized is that this is gonna require more than just a single look at a summer peak -- peak load scenario. You know, at a summer peak, you know, the solar generation perhaps may be only at 50 percent of its output or so, so -- and wind generation probably less than that, you know, at a peak period, possibly. So we're gonna be talking with the North Carolina Public Staff about adding some scenarios to look at where -- not only looking at summer peak, but including other times of the day when solar generation would be closer to its nameplate; wind -- another scenario where wind would be more at its maximum; and possibly some other, you know, times of the year, possibly winter peak, but it would be a series of different times of the year and different levels of load to more fully analyze this scenario.

That is -- as I say, that is underway. There is hope to get this study complete by the end of this year, but depending on the ultimate scope of this, it may run into 2022 somewhat before it is completed. So next slide, please.

So answering the question of how the collaborative studies inform cost in the IRP. So Sammy mentioned this -- or Mr. Roberts mentioned this back in his presentation that the 2012 NCTPC offshore wind study, some of the information from that study report was used in the 2020 IRP. So as we went into, in the fall of last year, 2020, the only offshore wind study that we had available to us to draw upon was this 2012 NCTPC offshore wind study, which actually was a joint study with PJM at the time. That report for this study is on the collaborative website. It came out in January of 2013.

So what was used in these -- on the table to the right here, the 70 percent carbon reduction scenario and the no new gas scenarios, included 2,650 megawatts of offshore wind. So there were scenarios in the 2012 collaborative study that included some various amounts of offshore wind generation. There were two fixed sites given in that study, and they were in the Morehead City area and the Southport area. So there were two different locations looked at, but the projects that were developed in scenario 2 -- there were three scenarios, but scenario 2 most closely matched the scenarios here that are circled in red, in terms of the amount of offshore wind being analyzed.

So those -- the projects that were in that report, that 2012 study report, the cost assumption, such as the cost per mile of 500 kV line, those cost assumptions were updated for the 2020 IRP; those costs had gone up in cost based on our latest estimates. So those cost were updated, and that's what was used in the 2020 IRP for estimating the transmission costs for offshore wind.

So the other two studies that are on this screen, the study that was just completed in

June, the public policy request, that study will be available now -- is available now, and we plan to use that as input into the 2022 IRP. That study is a very logical progression of the earlier study, in that, instead of assuming a location where the wind might be injected, this new study examines many -- 32 different sites where wind can be injected and gives us more intelligence about where the best places to inject wind will be.

We also should be done with the study that's underway now, the future renewable resource scenario study that we're working on now, and that study -- those study results should be available also for the 2022 IRP for estimating transmission.

So I do want to say that the -- I just want to make the point that the NCTPC types of studies have some limitations, in terms of informing the IRP, being that, you know, the official binding generator interconnection studies are not done -- cannot be done in this process because of the formal FERC and state processes procedures that we have. But studies here can be informative to the transmission planning process. It just does have some limitations. So with that said, I'm gonna pass this on to Mr. Roberts to summarize our points.

MR. ROBERTS: All right. Thank you, Mark. So in closing, I would like to provide how we see transmission planning informing the 2022 IRPs. We will have system impact studies for more recent generator interconnection requests reflecting network upgrade costs and will utilize those costs to refine our transmission network upgrade cost estimates for incremental resources. In fact, we should have results from the phase 1 transmission cluster included at that time and will incorporate those for our dollar-per-megawatt cost proxy as well.

We will also investigate the feasibility of creating a timeline for necessary critical transmission network upgrades to enable interconnection of the IRP portfolio resources. And this will identify network upgrades that are potential candidates for a proactive coordinated planning approach to enable interconnecting incremental resources in a timely manner.

We will also incorporate the applicable information from the updated and new North Carolina

Transmission Planning Collaborative studies, as Mark just talked about, for offshore wind and the higher renewable scenarios that he discussed.

We will investigate the potential and associated cost for an off-system capacity purchase, most likely focusing on PJM as the source.

And lastly, in the 2022 IRP ISOP stakeholder process, we'll address the analytical methods being developed in integrated system and operations planning for estimating the most cost-effective grid upgrades and associate- -- upgrades associated with the incremental IRP resources. So now I will be glad to answer any questions from the Commission and Commission staff.

COMMISSIONER CLODFELTER: All right. Thank you, gentlemen. As we did last week, we will open questions with questions from the Commission staff.

Before I do that, though -- and, Mr. McDowell, you check me if I am wrong about -- in what I am about to say. Let me suggest to Commissioners that, when we're asking questions this morning, we have scheduled -- at least the last time I looked, we had scheduled a separate presentation on the offshore wind study. I believe it's in November at some point. So you will have an opportunity to ask questions on that particular topic at a later session. And so, in the interest of time this morning, let me just ask, if you can, if you've got questions about the offshore wind study, if you could hold those, we will have a separate session, Mr. McDowell, unless it's been canceled.

MR. McDOWELL: No, that's correct.

COMMISSIONER CLODFELTER: And with that, we will open questions, and Mr. McDowell, you're up.

MR. McDOWELL: Okay. Thank you. I don't have any questions for Mr. Wintermantel. We do appreciate the documentation that's provided in the current IRPs relative to resource adequacy. It's very good documentation. Appreciate the remarks this morning.

I would say, as the Commission stated in its order setting up the technical conference, we recognize and appreciate the expanded discussion in the new chapter on grid requirements that's included in the IRPs. It's very good information. Reading from that chapter, it states that the six portfolios presented in this IRP included different assumptions for coal plant retirement dates along with a varying array of demand- and supply-side resource requirements to reliably serve load over the planning horizon. The Company conducted high-level assessments -- and I emphasize high-level assessments, which you've discussed today -- to estimate the associated necessary transmission network upgrades for retiring the existing coal facilities and integrating each scenario's requisite incremental resources.

And as I understand the discussion today, it's this high-level assessment that is the basis for the transmission investment requirements that are denoted in Mr. Roberts' slide. That's the slide entitled "2020 IRP Portfolio Results With Transmission Cost Estimates." I believe that's correct.

MR. ROBERTS: Yes, that's correct.

MR. McDOWELL: Okay. Good. Going back to Mr. Byrd's remarks and his history with the utility. I would say that I think Mark and I started at the utility at the same time, so good history there.

This chapter, as I go on to read, states that extensive additional study and analysis of the complex interactions regarding future resource planning decisions will be needed over time to better quantify the cost of transmission system upgrades associated with any portfolio. And I think we can all agree on that and appreciate the comments there. Again, I was reading from what's documented in the IRP. It's -- your comments are consistent with that and we appreciate that and emphasize, you know, the complexity of that. So we appreciate that.

And then, in this discussion in the IRP, again, you go on to address risk, and I'm particularly interested in that. Again, in this same chapter it states, given the long lead times for planning, siting, permitting, and construction of new transmission, there is some risk that some of the projects could not be completed in time to support the in-service dates contemplated by the more aggressive scenarios. Those more aggressive scenarios are those outside of the base case as presented.

We understand you can't retire generating capacity until the replacement resource is in place, correct? And that includes transmission, infrastructure, needed upgrades, et cetera; is that correct?

MR. ROBERTS: Yes.

MR. McDOWELL: So in a minute, I want to ask you how you are working to mitigate the risk the Company referred to in the IRP, specifically that statement. You just -- you just mentioned a timeline for the necessary transmission network upgrades. So a timeline, you know, as I envision what you were saying, is part of working to put in place some things that help to mitigate that risk, especially in terms of having projects completed in time to retire units, et cetera. So I want to probe that a little bit. I will give you a minute to think about providing some color around how the Company works or is planning to mitigate risk there.

However, while you're thinking about that, let me refer to the section of the IRP that addresses transmission planned or under construction. So in the filed IRP, there is a whole section, transmission planned or under construction.

First of all, I will note that, in the DEP IRP, there are six projects identified. According to the DEC IRP, however, there are presently no new lines 161 kV and above planned for construction in DEC's service area. So six projects in the DEP IRP identified in this section, again, the transmission planned or under construction. In the DEC IRP, there are no projects listed.

And when you look in that section, for each of the projects identified, there is certain information outlined for each project that includes the date construction started, projected in-service date, and docket number if one has been assigned. So there is not a whole lot of information there, but there are bulleted particulars for each project.

Three of the DEP projects do not include docket numbers, even though they have estimated in-service dates of 2023, 2024. Okay. There is not a docket number shown for those. And I realize

I'm looking at an IRP that was filed in September of 2020. I didn't look this up, but I assume, for example, like, the Porters Neck 230 kV tap line that's included that was to begin construction in January of this year has now been docketed and moving forward; is that correct?

MR. ROBERTS: Mark, do you want to come off mute and answer Mr. McDowell's question?

MR. BYRD: Yeah. I believe that that would be correct, Mr. McDowell. I know there is -- you know, I know there is an update that's being given to some of the Public Staff members later today, in fact, that includes Porters Neck. So I'm really not sure about the docket, but I would expect that it has been filed at this point.

MR. McDOWELL: So obviously my interest there in what's shown, at least for DEP -- and again, DEC does not have any projects shown, but at least for those six DEP projects, there are projects with in-service dates that are 2023, '24, and so I'm just -- I'm sensitive to this -- you know, this idea that the timeline for planning and implementing and constructing such projects, transmission -- these may not be major transmission lines, but they are listed, so I'm a little bit sensitive to that.

So here's a question. Does the Company begin right-of-way acquisition before seeking a certificate?

MR. ROBERTS: Mark, do you want to answer Steve's question again?

MR. BYRD: And again, I'm not really involved intimately in that part of the projects, but I would think not. It would have to be, you know, a special situation, I would think, for anything like that to happen. I would think that Duke would need to get the certificate before going forward with right-of-way acquisitions.

MR. McDOWELL: And right-of-way acquisition, obviously, is quite a chore, I understand.

MR. BOYD: Right.

MR. McDOWELL: So what does the term "planned transmission," as used in this section, mean? So, again, I'm referring to that section of the IRP that's transmission planned or under construction. So what does that term "planned transmission" mean, to suggest that it should be --

projects should be listed in the IRP there? Is it transmission associated with base portfolios only, or does it include transmission required to implement other portfolios identified in the IRP, or is it just docketed? Well, clearly, that's not the case, because some of these projects aren't docketed. Just interested in what the requirement is to include a project or not include a project.

MR. ROBERTS: Again, go ahead, Mark.

MR. BYRD: Yeah, my -- I can give you, for Duke Energy Progress, you know, plan would be, you know, what we consider in our 10-year transmission additions plan, you know. I know that sometimes there can be -- like, for the North Carolina Transmission Planning Collaborative, we have categories of projects, and there is a conceptual category, which means, you know, it may be further out, less certain, whereas planned means we intend to do it. Plans could change, but we intend to perform that project, construct that project. But, of course, under construction means that some part of the project -- you know, right-of-way clearing, some part of the project is actually started.

MR. McDOWELL: Okay. You don't know if DEC and DEP have two different criteria for what's included in the IRP for planned?

MR. BYRD: I'm not aware how DEC -- their interpretation of that is.

MR. ROBERTS: So the one thing I would mention, Steve, is, as you stated, it's for -- as the order is written, it's for 161 kV and above. And on the DEC system, 230 kV is primarily volt power transmission, and there is not any taps allowed to that, because it is volt power transmission between the distant load centers of the Triad to Charlotte, et cetera. And so, you know, most of the resources for which you would need upgrades would be on the 100 kV system, and, of course, that wouldn't fit this criteria, and so that's not gonna show up. And I'm sure there is some 100 kV upgrades that, if you did have that 100 kV and above, would show up in this list for DEC.

MR. McDOWELL: Okay. Thank you for that. I'm just -- I'm just looking for evidence that work, planning, execution of work necessary to effect these retirement dates and/or incorporating the generating capacity through all these portfolios can take place and is part of what mitigates the risk that was described earlier. Okay. So thanks for that.

So I guess I've stalled long enough to give you a chance to think about the question of how the Company mitigates that risk. Specifically, the risk that some of the projects could not be completed in time to support the in-service dates contemplated by the more aggressive scenarios. Can you speak to that risk and how the Company plans to mitigate that risk?

MR. ROBERTS: Yeah. So we look at alternatives associated with transmission planning additions, and those alternatives can mitigate risk. For example, one recent scenario, we looked at, you know, was it economical to utilize a battery to fulfill the mission of the transmission upgrade -- it couldn't be a long-term solution, but it could be a short-term solution -- if it looked like that transmission project was gonna be delayed because of supply chain, et cetera. So to mitigate that risk, one of the alternatives we considered was a battery.

Well, the risk was mitigated in other

ways, and so we won't need the battery and we can go ahead and get the upgrade done and meet the deadline by the transmission additions plan requirements. So that's an example of mitigating risk.

The other risk -- you mentioned transmission associated with resources, so I will carry that to all-system resources. You know, we can control very effectively things within Duke's control, Duke's service territory. Once you have an external system transmission owner that has to construct an upgrade to facilitate something like a capacity purchase, you are at, sort of, the mercy of their schedule.

Now, they know that in order to procure that firm capacity contract from all-system, that upgrade has to be done by a certain point in time, but there is risk associated with that. And even then, Steve, there is -- you know, I can remember being in the control room in 2000- -- August of 2007, and PJM calls us and says, we're issuing a TLR-005 and we're gonna cut your Kerr Dam purchase and your Rockport purchase. So there is still risk even after a firm capacity resource is contracted with respect to external system. But with that said, we are willing to look at that to see if it's a cost-effective capacity resource for our portfolio.

MR. McDOWELL: Okay.

MR. SNIDER: And, you know, Steve, if you think about moving to queue reform, for example, you know, we are looking for ways to make the interconnection of incremental resources more efficient. Sharing the cost across multiple -- you know, that's a way to mitigate risk of your ability to move incremental renewables onto the system more efficiently and quicker.

I think Mr. Roberts pointed out, you know, some of these require regulatory approvals, you know, in terms of, you know, what is triggering the transmission and how do you then go forth and build that transmission, right? So we needed several regulatory approvals to move through queue reform. You know, could we have other, you know, transmission projects that will require regulatory approvals? You know, that remains to be seen. But I think one of the things I would add to this discussion is, you know, you need to have, what is the catalyst for building the transmission? Is it load growth and you're upgrading your grid to accommodate load growth? That's one catalyst. As Mr. Roberts pointed out pretty effectively, you know, interconnecting new resources is a second catalyst. You have to identify and know where those resources are before you can build that transmission. And then reaching into other balancing areas, I think Mr. Roberts also pointed out very well, which is, you know, you have to carefully plan that with -- and coordinate it with your neighboring balancing area as well as your own balancing area, but you have to have that catalyst to do that.

So, certainly not the expert that you have on the rest of this panel, but the way I think about transmission planning a lot of time is what is the catalyst that is driving it? When does that catalyst -- you know, when do I get the CPCN, for example, for the new generator? That's a prerequisite before I can build the transmission to that new generator. So how do we make the entire process more efficient? You know, I think we are striving to do that in many ways, and I would just say, you know, queue reform is a good example of it. And, you know, we'll look to continue to figure out how to interconnect new generators more efficiently and in a quicker manner.

MR. McDOWELL: Okay. Thank you. I started off kind of referencing back to something that was in key takeaways, and that was the bullet that said determine feasibility of providing a timeline for necessary critical transmission network upgrades.

We don't necessarily -- in the IRP, I don't think we necessarily see that timeline. Obviously, that timeline or the project plan in total is critical to having these in place to be able to retire the unit you are planning at a certain date, et cetera, and I guess that pertains to transmission infrastructure as well as fuel supply, et cetera, et cetera, et cetera. So, yeah, interesting. Thank you for that. Any other comments relative to mitigation?

(No response.)

MR. McDOWELL: Okay. I guess a question for -- well, let me go back to Mr. Roberts' slide on 2020 IRP portfolio results with transmission cost estimates. So we have got cost estimates there, which you have described, high-level, and is the basis for the cost estimates we see, and they vary across those portfolios.

If a person was interested in the transmission build-out Duke envisions under each of these portfolios, you really couldn't go too deep in describing that, could you? Because, again, they're high-level estimates, the complexity becomes an issue, where this distributed generation is, et cetera. So if somebody was saying, okay, given this portfolio and this couple billion dollars that's over here, what's the difference in that than another portfolio, I'm just curious as to how much detail can be provided there.

MR. ROBERTS: Yeah. It would be difficult to really drill down with any degree of accuracy. As you stated, Steve, megawatt size, location, resource type, all of those variables -- and the number of resources in a certain area wanting to interconnect -- all of those variables play into what network transmission upgrades would be needed to facilitate that interconnection.

Now, the one piece of information we do

have is we have our queue. So we see where generators want to locate and interconnect, and so we can use that information to assist with developing that cost or looking at the transmission that's going to be needed going forward. I think on one slide I said if we want to connect 4 to 5 gigawatts of solar, looking at our transmission queue, we see common network upgrades that are gonna need to be absolved in order to facilitate that amount of interconnection of solar.

MR. McDOWELL: Okay. Good point.

MR. SNIDER: You know, Steve, I tend to think of it as that continuing -- you know, that funnel we described last week, right? As we move deeper into the process from initial screening to detailed planning to execution, you have more and more known information, and so you can get more specific, right? So you hit on some great points. You know, we have general ideas of what tranches of solar will cost to interconnect, because it's queue informed, but we don't know the exact location of those. We have general ideas for offshore wind, but until the precise volumes and landing point is known and how much solar is also in the eastern area -- remember, you are bringing that offshore wind from east to west, and it's got -- and there is a lot of solar in the east as well. So until you know exactly how much solar is in front of the offshore wind, where the offshore wind is coming ashore, how many megawatts, you can only get so precise in your funneling process.

MR. McDOWELL: Right.

MR. SNIDER: You know -- and, you know, we did, I think, a -- for the first time in 2020, a really, you know, good job of saying, you know, here are -- here's what it costs to replace, from a transmission perspective, if I do or don't put the coal back -- or put a replacement resource back at the retired coal sites. In some cases, I have to fix a transmission issue by the hole I've created, and then I've got to site the new generator. And other cases, if you were to locate there, you would have some transmission synergies. So we try to, in that winnowing process, provide more detail than we've ever provided in an IRP. You know, we'd love to have the exact numbers, but until you get to the actual execution phase and understand all the variables Mr. Roberts spoke about, as well as what's happening around you, you can only go so far in getting precise in that transmission estimate.

MR. McDOWELL: And as you move down that funnel, the complexity of the analysis really increases. Even though you've got additional information, you've got a lot of other variables that come in there. So I appreciate the comments of the complexity of that as well, because it's not simple, even though you get more information downstream.

MR. SNIDER: That's a very good observation.

MR. McDOWELL: So a couple of questions for Mr. Byrd relative to the NCTPC. Why do the annual studies look out 10 years in the future as opposed to 15 or 20 years?

MR. BYRD: Yeah. I think that -- I know that, you know, for my whole time I have been in transmission planning, you know, our time horizon generally has been 10 years is how far we looked out. And I think it has to do with, you know, the accuracy of the models, the -- you know, the load forecasting, the limits of our load forecasting, of our predicting, you know, what future resources we will have. I think, more than ever, right now it's really hard to do transmission planning if you don't know where your future generation resources are going to be located. You know, you can do studies -- even at 10 years out we have to sometimes put in we call pseudo generators to, you know, make up enough generation to serve a load, even though we don't really know where that generation is going to be located. So I think that's the main limitation, is knowing where the resource is going to be further out than that 10-year horizon.

MR. McDOWELL: So if the annual studies did go further out, say 15 years, if Duke built the indicated transmission sooner than later, right away instead of just in time, would that create headroom on the grid that would ease the interconnection of more renewables?

MR. ROBERTS: So, as per -- oh, this is for Byrd, I'm sorry. I'll let him answer.

MR. BYRD. So if I understand, your question is, you know, in the reliability analysis, if we would build the transmission sooner, would it support adding more generation. I think there is no certainty of that at all. Again, we have to know where the new generation is going to be located. Just improving, you know, our reliability margins on what we know now would not necessarily help us connect more generation, not knowing where it's going to be located.

MR. McDOWELL: So are those assets, those transmission assets, that are -- would be needed to serve load fundamentally different than the assets that would be needed to address the interconnection queue?

MR. BYRD: That is correct. In general, that is correct. You know, it depends on the locations, and that's, you know, what's challenging about this scenario is, what assumptions do we make about where -- future generation that's unsited, where it's going to be located.

MR. McDOWELL: So, in the future, would the NCTPC study incorporate a chosen portfolio path? Does that start to be addressed in the base or is it always addressed in these additional studies? How do we view that in the future?

MR. BYRD: Well, it's -- I think that's a good question that's yet to be seen. I mean, I think, traditionally, there's been sort of a base model, and that's the assumption that things are gonna continue on in that path. I guess, you know, kind of a unique -- starting in 2020, there were six different portfolios. And so, I don't know. In the future, you know, if there is a selected one, I'm assuming that it would become the plan. And, you know, once those locations are known, I think that would be the assumptions of the collaborative in their plans.

MR. McDOWELL: And it's each of those plans that are utilized to inform the IRP, such as the work underway now that will inform the 2022 IRP; it's not necessarily just one portfolio but the different views and implications of offshore wind or wind from Oklahoma or whatever, right?

MR. BYRD: Right. I think the offshore wind is a good example, where, you know, we are developing our knowledge base as we do more studies. We are learning more. It's a little bit unique in that it's, you know, bringing large amounts, you know, from eastern -- you know, from the ocean, basically, toward the west. And so I think we're gaining knowledge as we do more studies on that that would help us guide, you know, a way to more optimize wind if we make that decision to go forward with offshore wind.

MR. McDOWELL: So with these different portfolios that are identified in the IRP, what are the trigger points for doing things, like starting to secure right-of-way or some of the other planning or actual execution on some of those?

MR. BYRD: Right. Today that would start when there is a generator interconnection agreement signed for a specific generator. At that point, it becomes, you know, a firm resource and transmission planning then can start, you know -- you know, the process for actually performing the projects that were identified in the studies leading up to that point. The transmission that's needed, it would then start to be constructed. Engineered and constructed.

MR. McDOWELL: Right. So I guess it's fair to say that -- say that transmission right-of-way that's -- that will be needed is not necessarily already owned or being purchased by the Company to effect what may be necessary to implement some of these portfolios, including offshore wind.

MR. BYRD: That is correct. It's -- I mean, obviously, we look -- you know, we have information and we -- about existing right-of-ways that we do have available, and that's part of the process, but I think it's probably likely that we do not have all the right-of-way -- there would be new right-of-way needed for large amounts of new generation resources.

MR. McDOWELL: The thing we know is, like, if you're gonna bring that much offshore wind in, there is not sufficient load on the east coast, so it's got to be moved, and there is significant -- which, like Commissioner Clodfelter said, we will hear from that study later, but we know there are impacts to enable that then, or at least to get it to the load centers.

MR. BYRD: That is correct.

MR. SNIDER: Steve, you know, one thing to keep in mind too, as Mr. Roberts pointed out, is in what volumes, right? So there is a difference between 1,000 megawatts, 1,500, and 3,000. So you have to be thinking about what is the likely scale of that resource gonna be, and are you gonna do this in increments or are you going to envision a larger scale and prepare for that larger scale, and what regulatory process would be needed to do that, right? So let's say the first tranche came in at 1,600 megawatts. Well, is that really a sustainable economy of scale for offshore wind, or would you end up with more? If you end up with more, should you be doing two separate transmission projects or should you envision more in step one so that you can get better economies of scale and a more optimal solution, and I think that's what Mr. Roberts was alluding to in his presentation, which is, is this a push or a pull, and what's required -- you know, what's the catalyst to allow you to build out that transmission at the appropriate economy of scale if it's not being part of a specific interconnection agreement request? And that's the difficult part right now, because the current process doesn't really allow for us to just build a larger transmission grid --

MR. McDOWELL: I understand.

MR. SNIDER: -- with that interconnection agreement in place. So that is something that the industry is going to have to wrestle with in the coming, you know, years.

MR. McDOWELL: And as you decide how to build that out incrementally, or whatever, there are implications downstream with -- associated with solar projects here, there, across the whole eastern part of the state, and what opportunities that provides for too that are in the queue and otherwise, right?

MR. SNIDER: Absolutely. I mean, it's a portfolio view that you're looking at, and it certainly affects it.

MR. McDOWELL: So coming from the other direction, you mentioned the public policy request that the Public Staff submitted and mentioned the, I think, 2,500 megawatts of wind to be studied coming from the Midwest. I guess, coming to our system by way of Southern Company or wherever, does that include the transmission necessary to bring the power to Duke's service area or is it just the interconnection there?

MR. ROBERTS: Yeah. So you're talking about the Oklahoma wind?

MR. McDOWELL: Yes.

MR. ROBERTS: So for the Oklahoma wind

import, the only thing that was estimated was the upgrades on the Duke Energy Carolinas' side of the interface, but, you know, you've got to get the wind energy from Oklahoma, and I think the clean line project was, like, somewhere in Tennessee, TVA's area.

MR. SNIDER: That's correct.

MR. ROBERTS: And that was, like, $2-and-a-half billion of transmission to get it to that point. If we look at importing it into DEC, that transmission path from that substation in TVA's area all the way through Southern Company into DEC has got to be constructed or upgraded in order to facilitate that imported if we want it to be firm. So there are additional costs associated with being able to import Oklahoma wind.

MR. McDOWELL: Okay. So that hasn't been studied or envisioned in the -- in the study that's underway for this public policy analysis; is that correct?

MR. BYRD: That's correct. Typically, upgrades that might be needed on other people's systems would not be part of the scope of this study. But really, the impact it would have on the

Duke Energy transmission system would be what would be determined in this study.

MR. McDOWELL: So, Mark, you're saying Duke customers wouldn't have to share in that cost?

MR. BYRD: No, not really saying that. It's just that that will -- you know, the cost -- you know, like the wheeling costs, you know, will be annual -- well, monthly fees for wheeling. You know, there will possibly be different rates for those upgrades. You know, that was beyond the scope of this study.

MR. McDOWELL: Okay. I think that's all the questions I have. I appreciate it. And again, there is some really, really good information in the IRPs, themselves, and I appreciate your comments today. Thank you.

COMMISSIONER CLODFELTER: All right. We have been going just about exactly an hour and a half. Let me do a check-in. I don't recall, as I sit here this morning, because I don't have my cheat sheet in front of me, how many additional presentations we have today. I know intervenors have one presentation; is that correct, Mr. Smith?

MR. SMITH: Yes, that's correct. NCSEA

and NCCEBA have one presentation.

COMMISSIONER CLODFELTER: And the Attorney General has a presentation, correct?

MS. TOWNSEND: That's correct.

COMMISSIONER CLODFELTER: Mr. Josey, what about the Public Staff? Mr. Josey?

MR. JOSEY: Excuse me?

COMMISSIONER CLODFELTER: Presentation from the Public Staff?

MR. JOSEY: Yes, there will be a presentation from the Public Staff.

COMMISSIONER CLODFELTER: Okay. Folks, we have got -- an hour and a half is about all we have got, and we can slide just a bit, but we are gonna start losing Commissioners. I'm gonna lose one at 11:00. So I'm gonna give our court reporter a 10-minute break here right now. We will come back at 10:40, and we'll start with Commission questions on the Duke presentation. And, folks --

MR. McDOWELL: Commissioner Clodfelter, this is Steve. I do not anticipate having questions for any of the presentations downstream.

COMMISSIONER CLODFELTER: Thank you for that. I just want to be sure we have enough time for them to get through the presentations. So let's just see where we are. We'll be as flexible as we can. Court reporter comes first, so we'll take a 10-minute break here and come back at 10:40. Please mute your mics and stop your video.

COMMISSIONER McKISSICK: Commissioner Clodfelter, I'm gonna have to leave at about 11:45.

COMMISSIONER CLODFELTER: We are going to be losing folks anyway beginning at about 11:00, so let's come back at 10:40.

(At this time, a recess was taken from 10:31 a.m. until 10:40 a.m.)

COMMISSIONER CLODFELTER: All right. We'll pick back up with questions for the panel from Commissioners beginning with Commissioner Brown-Bland.

COMMISSIONER BROWN-BLAND: Commissioner Clodfelter, I don't have any questions, but the discussion and the presentation have been appreciated. Thank you very much.

COMMISSIONER CLODFELTER: Indeed. They have been excellent. Commissioner Gray?

COMMISSIONER GRAY: No questions, but I

echo the comment.

COMMISSIONER CLODFELTER: Chair Mitchell?

CHAIR MITCHELL: I, too, appreciate the information that y'all have shared with us today. I have, actually, a number of questions, but I'll just be quick with one or two of them in the interest of moving along.

This one is for Mr. Wintermantel or Mr. Snider. Mr. Snider, since you're with us today, you're gonna take in some -- I'm hoping you can help.

Mr. Wintermantel, you mentioned in your remarks that Duke is already a bit more aggressive than our neighbors TVA and Southern Company with respect to the firm reserve margin. So you noted that we have the 17 percent all-firm margin here and TVA and Southern, they are like, I think you said, 22 and 25. Just tell me if I have gotten that wrong. And then you mentioned Duke's generator performance. I think I understand the point you're making, but can you connect those dots for me so I can make sure I understand exactly what you're saying?

MR. WINTERMANTEL: Sure. Sure. And overall, it's more of just a comparison of reserve margin in general. So TVA -- I'm kind of going back to my notes here -- looks like they are at 25 percent winter reserve margin target and Southern Company is at 26 percent. So that's comparable to the 17 percent in Duke.

Now, without going and digging details into those studies to understand why that is, I'm somewhat speculating that part of that is because of the large amount of reliance on non-firm imports in the Duke studies. We know those numbers; we perform the study. That's that 5-to-8 percent range, but I also think there could be other reasons, and that could be, you know, I think, the generator performance by the Companies, because that's based on historical data. So we look at the historical outages and we try to model those, calibrate the history. I do think the Duke generators have performed pretty well. I think -- in the appendix of the report, I think you will see 3 to 4 percent type E4s which are pretty good, so.

CHAIR MITCHELL: Okay.

MR. WINTERMANTEL: Mr. Byrd or

Mr. Snider, do you have anything to add there?

MR. SNIDER: No. I think, you know, it's load response, it's generator perform- -- you know, what are you solving for in a reserve margin. It's abnormal weather and outages as well as load forecast error, right? And so, you know, if you look across those three big variables that you are solving for, why do I carry a reserve margin? It's to solve for those three, you know: extreme weather, unit outages, and load forecast error. So we -- in our reserve margins, we assume little to no load forecast error, others may assume load forecast error. The fact that you might miss the long-range forecast.

Our unit performance, as Mr. Wintermantel pointed out, is strong, generally, which helps us carry a lower reserve margin. But we do have that winter peak response that we need to be accountable for, and we need to see all our Southeast peers doing the same. So those are the three, and I think across those three we carry slightly lower than our peers, and it's hard to parse out which one of the three buckets is causing us to carry the lower reserve.

CHAIR MITCHELL: Okay. And that's very helpful. Thank you. Thanks both of you for your responses there. That helps me sort of connect the dots there and better understand the points that Mr. Wintermantel was making.

All right. Last question, and any of y'all can answer this. We heard from y'all today about -- extensively about, sort of, the transmission planning process that the Companies historically engaged in. I heard that the transmission planning horizon has been 10 years historically, and I think I understand why that's the case.

You know, I guess -- and I also heard -- and I think this was Mr. Byrd -- say, if you don't know where future resources -- or future generating resources are going to be located, it's difficult to, sort of, drill down in detail on the -- on the transmission side. And so there is sort of a chicken and an egg that goes on, and I very much understand that.

But as we move forward, you know, what are we going to do about this chicken and egg? And I think what I've heard Duke say is, it's a chicken-and-egg conundrum. And what I think I've heard at least some folks for Duke say is that perhaps we need to look at a more proactive approach to transmission planning. And, I guess, someone, sort of, summarize for me what we -- what we are going to do as we need to increasingly focus on, sort of, the interplay between transmission and generation as we contemplate these new builds and retirements and, you know, the need to understand costs associated with both as we make decisions for the future.

So just so I'm clear, you know, we need to -- how do we get to the point where we can evaluate all costs associated with new additions, both transmission and generation, with as much certainty as possible as we face, sort of, this future of adding new and different types of resources? So that's -- someone just take a shot at that and then I'll -- that will be my last question.

MR. ROBERTS: So, Glen, I'll start, and you can pick up behind me. So we have taken one step with that in the cluster study process. And, you know, with that process and getting that implemented for both state and large generator interconnection FERC jurisdiction queues, that will hopefully dilute costs and take care of some of these larger upgrades. It may. That's one of the purposes of going to the cluster study.

I think, going forward, with looking at the volume and magnitude, megawatts of resources, especially concentrated, as you see in the portfolios, like solar, I think that the cluster study process, if it doesn't take care of that, we're gonna have to have a proactive approach in order to meet the timelines associated with integrating these resources. And when I say "timelines," I'm talking about, you know, being able to have, say, all coal retired by 2030, for example. Those sorts of timelines we're gonna have to have -- if that's the direction we pursue and the Commission approves, we're gonna have to have some kind of proactive approach.

MR. SNIDER: And let me just add briefly, we do -- you know, we are proactively studying around each of the coal sites, if I don't replace, what do I need to do. And we have a plan in place to execute for that. If I do replace on site, how does that help me? We can study that in some amount of detail.

To your point on the chicken or the egg, it's, if I don't replace on site or -- and it's not an all/or, right? It's probably maybe some is on site and some is not. Where -- for that resource that's not being replaced on site, you know, is it going to continue to be a -- the catalyst needing to be the IA -- you know, the interconnection agreement is needed prior to the build, or do we get to a situation where you have an informed view of where you think resources are most likely to site and you try to build a very cost-effective larger-scale project that allows more to interconnect, so it's more of the pull. I call it either a push/pull, right? Is transmission being, you know, sort of pushed by IAs, interconnection agreements, or are you building a grid that allows for the effective connection of a lot of resources and you're pulling resources into the system because you now have a robust grid from which they can connect.

And if you look across the country, I think you see some people doing both, right? Some where we're at were IA, but in other areas it's, hey, we think this is a very smart path for a lot of good reasons. You build out the transmission, and then you either build or solicit resources that can connect to that transmission. And I think that -- you know, that is something -- you know, especially as we want to add large amounts of renewables, it may be something to Mr. Roberts' points that we need to consider.

CHAIR MITCHELL: All right. Thank you-all for that additional information. And I have nothing further, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Thank you. I think this topic of this question will come up again when we have the presentation on the offshore wind study. There are some things in that study that speak to this question pretty directly. So we get a second chance to talk about it then.

I will move to Commissioner Duffley next.

COMMISSIONER DUFFLEY: Thank you. Thank you for the presentations. If I could ask a follow-up question on Chair Mitchell's question, and it's with respect to this proactive build-out.

And we heard Mr. Byrd talk about it's hard to plan when you don't know where the generation is located, but my question is, does it matter what type of generation connects, or are all megawatts the same? So if you did a proactive build for solar, but it's determined actually storage costs go extremely down and you're putting in something else, wind plus solar -- or wind plus storage, so the generation makeup is different than what you expected, does that make a difference or not? I'm just thinking about risk of stranded assets or risk of inefficient build.

MR. SNIDER: Go ahead, Sammy. You're the expert on this, and I will follow up.

MR. ROBERTS: So with respect to technology, it just, you know, depends on its capability with respect to how it's studied. For example, with storage, I think I stated in my presentation that we're gonna have to look at studying it for both absorbing energy from the system as well as delivering energy to the system. For solar, you have a peak around between noon and 13:00 in the afternoon. So that solar peak needs to be studied, as well as its contribution to summer gross load peak. So, you know, different resource types require different types of studies.

But to your point, I think the transmission build can further be utilized by other resources, and it can be a substitute resource, other than solar or solar plus storage, that can utilize that transmission build-out. Also, you know, I would add, with that transmission associated with wind, there will be some underlying lower voltage class upgrades that will be needed. And so that build-out of transmission to accommodate those incremental resources talked about prior, that same transmission could be utilized associated with the bringing in offshore wind and handling those contingency situations with a higher voltage transmission system that would be built for offshore wind.

COMMISSIONER DUFFLEY: Okay. Thank you. And just have a couple more questions, but I will try to go quickly. With respect to this type of proactive build-out, I heard some -- someone talk about the change of power flows, and with retirements of certain generation and additions, does the proactive build-out on help with that? Is that a factor as well, or not really?

MR. ROBERTS: Yeah. So if you retire generation and you don't replace it on site with a similar amount of megawatts, all of a sudden, you know, when that generation was online and provided counterflow or support for a certain area, that void is gonna be there. And that void, with respect to that counterflow, may exacerbate flow from, say, the south up to the north with respect to retiring Roxboro plant and not replacing it on site. So, yeah, that proactive transmission can definitely help in that situation, if you retired Roxboro, didn't replace it on site, and you located more incremental resources to the south.

COMMISSIONER DUFFLEY: Okay. Thank you for that. Then, Mr. Roberts, you had a slide showing an example of network upgrades, and this is just a very -- probably too basic of a question, but -- so what is the -- you know, in PJM, they have several different drivers, right? They have the reliability driver, the market efficiency driver, and then, kind of, a state public policy driver for purposes of cost allocation. What's the driver for network upgrades? When we're talking about network upgrades in DEC and DEP, what is the driver? Do we have two different drivers as one, you know, to correct a NERC violation and then another driver might be to deal with, you know, market efficiency or congestion or bottled -- you know, reducing bottled generation? And if there are two multiple drivers, not just NERC violation drivers, what was the percentage of each?

MR. ROBERTS: So my limited understanding, Commissioner Duffley, is that network transmission is primarily for the purpose of serving the load. And so you're ensuring that the resources that you have on your system can deliver those megawatts to the load with proper network transmission. And so if you have an external resource, such as in PJM, coming into -- a new resource coming into the system, CPLE, that's how the study would be performed, is to ensure that that can be reliably delivered to the load -- to serve the load. So I don't think I answered your question fully, but I will let somebody else on the panel take a shot if they have further information to add.

MR. SNIDER: At the risk of --

MR. BYRD: I'll go. The distinction is, you know, when you are studying a new generator and you say it requires a network upgrade, that network upgrade then becomes necessary to -- for reliability, to meet the NERC standards to reliably implement that new generation. That, you know, if it signs an interconnection agreement, then it becomes part of your system, then that becomes a reliability upgrade. So I think that almost all of the network upgrades really have to do with meeting the NERC reliability standards. Some of them are generated because of new network resources or generators that are connecting to the system.

COMMISSIONER DUFFLEY: Okay. Thank you, Mr. Byrd. And then one last question, because I know we need to move on. You mentioned the clean line project, and, just, can you remind me if -- what would be the cost allocation for DEC customers of upgrades from TVA through Southern? You mentioned that upgrade would need to occur. What's that cost allocation?

MR. ROBERTS: Yeah. I don't know what the cost allocation is associated with that leg of the transmission path that would need to be firmed up to reliably import Oklahoma wind into DEC.

COMMISSIONER DUFFLEY: No worries. I just wondered if you knew off the top of your head. Thank you. That's all that I have. Thank you.

COMMISSIONER CLODFELTER: Thank you, Commissioner Duffley.

Commissioner Hughes?

COMMISSIONER HUGHES: Yes. Thank you. Could one of you comment on the impact we may see of large fleet electrification? How does this compare to some of the impacts we have been talking about in generation, and if it's on the same level, what kind of planning is going on and what will you see in the future? Because we haven't talked much about that here.

MR. ROBERTS: Glen, do you want to take a shot at that question?

MR. SNIDER: Sure. You know, let me start by saying, you know, again, it goes to the catalyst, what's causing the need for more grid infrastructure transmission. There's load growth, and then there's large generator interconnection, right, our two big catalysts. And, correct, Commissioner Hughes, we haven't really been discussing much about low growth and what low growth may do to require grid upgrades. But, you know, I think what you're talking about with, like, large fleet, you know, it will have, I think, first and foremost, probably distribution interconnection issues, in terms of, you need to have a robust enough distribution system to have charging stations for those large fleets that are converting from hydro fuels to electric. But then, in aggregate, that will also need a grid that can support that. So the catalyst for those upgrades works in -- comes in through the load forecast and the need and specific load pockets that are growing faster. It sort of speaks to some of the benefits of our ISOP initiatives where we're looking at more granular forecasting of distribution and transmission needs due to electrification and being able to be proactively building in front of it.

So, you know, to some extent, those come in through a different -- in my mind, through a different channel, triggering growth to meet native -- or triggering transmission build or mostly distribution build to meet pockets of load growth. And, you know, the whole ISOP initiative is gearing towards being able to be in front of that and plan for and predict, to Mr. McDowell's question about minimizing risk, not be surprised by where these requirements are going to happen and proactively planning for that growth.

I don't know if that directly answered your question, but, you know, I just think of that a little bit differently than large generator interconnection.

COMMISSIONER HUGHES: Are there surprises to come, or -- are you confident that it's imbedded now, or do we have some surprises in front of us?

MR. SNIDER: You know, I think, to the extent there is great debate over the pace of electrification -- not just large vehicle, you know, commercial, industrial, heating load being electrified -- we're gonna -- I think that really speaks to the value of having a robust ISOP process, because there certainly is gonna be surprises. If you read the literature, there is a variety of opinions on the pace at which electrification is gonna happen by sector, and, you know, you want to be in front of that and not slowing that. As the utility, with an obligation to serve, we certainly want to be in front of and promoting the appropriate amount of electrification, and I think, you know, certainly a lot of surprises to come. So I would say we don't know today exactly where that's going to be, but we're attempting to build an infrastructure and planning infrastructure that allows us to stay in front of it as the -- you know, as the industry unfolds.

COMMISSIONER HUGHES: Okay. I will look forward to those surprises. That's all the questions.

COMMISSIONER CLODFELTER: Thank you. Commissioner McKissick?

COMMISSIONER McKISSICK: Commissioner Clodfelter, in the interest of time, I am going to take a pass and not ask any questions, but I might suggest to you that we, as Commissioners -- maybe we could speed through the remainder of what we need to do and conduct if we consider submitting written questions. I know the written questions don't allow an opportunity for follow-up that we like to have sometimes. I think we have 58 minutes left.

COMMISSIONER CLODFELTER: You are thinking ahead, and I appreciate that. I have been doing likewise. I have a couple of proposals, but let's keep going for a while, and then I will surface those proposals, depending on where we are.

COMMISSIONER McKISSICK: Thank you.

COMMISSIONER CLODFELTER: Mr. Roberts, I have one quick follow-up to Commissioner Duffley's question. Mr. Roberts, are you still there?

MR. ROBERTS: Yes, sir.

COMMISSIONER CLODFELTER: The clean line project, is that classified and identified for planning purposes as a regional or an interregional project?

MR. ROBERTS: Yeah, so I believe that crosses two regions, so it would be interregional. And this project was conceived and costs were allocated to it back in the 2013 time period. So those costs will definitely probably need to be updated.

COMMISSIONER CLODFELTER: That's fine. If it's so classified, I could track down the follow-up information I need. Thank you for that answer.

MR. ROBERTS: You're welcome.

COMMISSIONER CLODFELTER: Members of the panel, that was a very high-quality presentation. You took the challenge I made on Friday afternoon and you met it, so I thank you for that.

We will move to -- Mr. Smith, you are next.

MR. SMITH: All right. Good morning. Mr. McCoy, could you allow me to share my screen? I will go ahead with my introduction while he does that. I am introducing Jay Caspary, who is a presenter on behalf of NCSEA and NCCEBA. Jay Caspary is the vice president at Grid Strategies, LLC. He's been there since September 2020. Prior to that he worked for 20 years at the Southwest Power Pool as -- among other things, but finally as the director of research development in tariff services. He also worked at the Department of Energy from 2012 to 2013 as a senior policy advisor on electricity delivery and energy reliability. And from 1981, I believe, to 2000 he worked at Illinois Power in various roles, including transmission planning-related roles.

Mr. McCoy, it still is not allowing me to share.

(Pause.)

MR. CASPARY: While that's coming up, can I start talking, since we have limited time?

COMMISSIONER CLODFELTER: You may do so. Thank you.

MR. CASPARY: Thanks, Ben, for running the slides, and good morning, Chair Mitchell and Commissioner Clodfelter. Thank you for giving me a chance to talk to you a little about transmission. I think it's very important that you're seeing -- you're realizing how important transmission is for long-range planning and to having an efficient grid, and I appreciate the chance to talk a little bit about this topic which is near and dear to my heart.

As Ben pulls up the slides, let me give you a little bit of background. I want to make a comment, I guess, on what Mr. Wintermantel said about Southwest Power Pool not relying on non-firm capacity resources in the determination of its planning reserve margin. And while that is true, I think it's important to also realize that Southwest Power Pool has a planning reserve margin target of only 12 percent, and that may seem very low, and it is low because it can be an effective level of reserves given several factors, primarily a robust transmission system that's been built over the last decade, as well as expanding markets and -- to accommodate more and more renewables and the ability to share resources across broad geographic regions and take advantage of load diversity and weather patterns and things like that. You know, a lot has changed, but I think bigger is better, and, clearly, that's one of the things that Southwest Power Pool found out and has actually benefitted their customers by lowering their planning reserve margin.

Ben, do you have my slides? Are you gonna go through them? I'm not seeing them, but that's okay.

MR. SMITH: They are coming up right now. I apologize.

MR. CASPARY: No problem. Let's move on to slide 4. I am going to fly through some industry overview slides really quick. I want to focus on the questions at the end, and -- but I appreciate any follow-up questions you might have about my slides.

Transmission and renewable energy are inescapably connected. If you look at the renewable resources that have the highest quality, generally they are far from load centers, and they require transmission to be delivered effectively and efficiently to customers.

One thing -- you will see that, in broad interconnection, wide- or even national-scale-type studies is the need for lots of major transmission connectivity to help balance the system and deal with, you know, wind excesses in the plains offsetting, you know, the lack of solar resources in the desert Southwest. And the same thing could be happening in the Southeast even, where you need transmission to provide flexibility and optionality to support grid operations and deal especially with things like extreme weather events.

On slide 5 I go over the generation interconnection queue. There is thousands and thousands of megawatts of generation that is stuck in the queues right now. It's good to hear that

Duke is trying to get to a clustering process. That's going to be much more efficient and effective for the GI clearing, but there is lots of solar and hybrid projects that are entering the queues across the U.S. Even in the Southeast there is 60,000 megawatts of solar in the queue, as well as about 40,000 megawatts of hybrid storage projects, and that's based on data from Lawrence Berkley National Labs.

One of the things that we see in all these big studies, it looks at, you know, how do we decarbonize this electricity system? We are gonna need lots of transmission. Most of those studies say we need two to three times as much transmission capacity that we have today. The good news is that we are rebuilding a lot of the existing system, and there may be opportunities to upgrade and rightsize, maybe even take advantage of new designs of transmission structures and configurations to increase the capability to move power down existing corridors without having to build new transmission lines.

So I'm a big fan of advanced transmission technologies, advanced conductors, as well as grid-enhancing technologies. And I don't think grid-enhancing technologies are necessarily an alternative to offset long-term transmission expansion planning, but definitely they are a bridge to the future. And they can help us accelerate the integration of renewables prior to the construction of major transmission upgrades that are going to be needed, but it just takes a long time to get those projects approved and permitted and sited and built and commercial.

Ben, are you having any luck on the video?

MR. SMITH: No. I have restarted -- oh, yes, here it goes. All right.

MR. CASPARY: Okay. Great. I want to spend a couple of minutes just to go over a study that was done, on slide 7, that talks about unlocking the queue. And just very briefly, Southwest Power Pool has about 9,000 megawatts of primarily wind projects that are stuck in the queue, and those are only in the states of Oklahoma and Kansas.

So what we did through the WATT Coalition on a study that was done by Brattle was to look at how many of those projects that are actually stuck in the queue can be integrated reliably to the system today -- in 2025, based on current reliability requirements, thermal and voltage criteria. And in a change case, we wanted to see how many of those could we add with the help of grid-enhancing technologies, specifically dynamic line rating, advanced topology, optimization, and advanced power flow controllers. And we did this looking at the aggregate combination and the benefit of those technologies.

Let's go forward. So we're looking at 2025 models based on the actual 2019 and 2020 experiences in actual operating models to see how many more renewables we can integrate on the SPP system using their reliability requirements and looking at lots of optimal power flows.

Let's go forward. I'm not gonna spend a lot of time on these technologies, but at the top right you can see that is the queue. The resources that are actually stuck and not moving forward, there is over 9,000 megawatts of wind. Most of that is in Oklahoma. Some solar in both Oklahoma and Kansas. But you can see that, in the base case, if we do nothing to take advantage of advanced transmission technologies or grid-enhancing technologies, you can integrate about 2.6 gigawatts of new resources in SPP reliably. Now, if we looked at adding grid-enhancing technologies, we can more than double that and -- which is significant. And I'm an engineer, and I expected to see an improvement, but nothing like this, and that's despite the fact that we used very conservative assumptions. Let's go forward to the next slide.

This analysis showed basically a six-month payback for these assets with potential benefits of over $175 million of annual production cost savings in SPP, and we extrapolated those across the U.S., and they are very, very big numbers on the left.

On the right you see, actually, how does the $90 million of upgrade compare to the cost of adding the new 2.7 gigawatts of renewables. And you'll see that it's very small. It's less than 2 percent of the estimated capital cost of the renewable projects. So I'm sure there is developers that would gladly fund these projects to get their renewable projects on line, connected, and serving loads sooner rather than later, and not having to wait for major transmission upgrades. Let's go forward.

The next slide just shows the actual details of the technologies that were being deployed. This would mean a lot to engineers that want to know more about dynamic line ratings, how many applications -- most of the applications are in the 138 and 161 system, and that forces the flow up on the 345 system, which is the backbone in SPP.

We will see a lot of circumstances where we use software to reconfigure the system to alleviate congestion on the system, which typically, again, is at the lower voltage systems that -- to force the flows up on the higher voltage systems that have a lot of latent capacity that we just don't utilize because we don't have sensors and we don't have knowledge and algorithms in place to help us take full advantage of potential reconfigurations of the system. The last technology we looked at were powerflow controllers. These are devices that actually help you to push power on the lines that have latent capacity or pull power off lines that are getting overloaded. These are proven devices that are being used around the world, and they are just not an incentive yet to deploy them in the U.S., and we are trying to work with the WATT Coalition and FERC on making that happen in a shared-savings docket. Let's go forward if we can. I'd like to get through these slides.

There is a lot of deficiencies. You've heard some of this. I don't want to belabor this issue, but the changing resource mix, and looking at how do you plan 10, 15, 20 years out in the future. We know there is very, very aggressive decarbonization goals by utilities, by customers, by states, municipalities, that aren't being reflected in current plans, and I think it's prudent for us to look at what we really think is gonna happen in the future. Even though we are gonna have to make assumptions about resources, we do that about loads today and other parameters that drive our power flow analysis. We can do this. We just need to, kind of, think a little bit outside the box. Let's go forward, if we can, to the next slide.

One of the things I'd encourage you to look at is the report we published back in January that looked at planning for the future and how things could be done differently and more efficiently if we'd look, basically, at more wholistic planning, to focus on actually what do we expect the resource mix to be? What are the benefits of adding transmission capacity? You know, it's not just economic benefits. There is probably reliability benefits, security benefits, and other benefits that transmission provides us because it is such a flexible resource that provides lots of optionality for future resource plans.

So this report is posted. I'd encourage you to check out the report as well as the website and the video that's included. I think over a dozen of the former FERC chairs that supported this effort, and a lot of that is being rolled into the ANOPR right now that's going on at FERC with comments due next week. So it's a timely topic. Let's move forward if we can. Thank you.

Winter Storm Uri is a classic example of the major benefits you get from transmission that probably weren't considered when you approved it, designed it, and got it built in place. So many of the projects in SPP as well as MISO have been built to move wind energy from west to east. These same projects were critically important to provide critical service from PJM in the Southeast to the West during Storm Uri. There's been analysis that shows that ERCOT could have benefitted by saving $1 billion if they had an additional gigawatt of connectivity to the Southeast. Projects like Southern Cross would have provided twice that. 2,000 megawatts of capacity into the ERCOT market would have saved a lot of money and a lot of lives and helped them ride through that storm.

Other things about the NERC -- and FERC have just released a preliminary report on the findings, and they talk about how we need to do studies of large power transfers on stressed systems, and that ERCOT needs additional connections, and that's not a surprise. It would have helped immensely if they had.

The next slide shows what happened on February 12th -- February 15th, sorry, and the congestion that's shown in the Illinois/Indiana border between the PJM system to the east and the MISO system to the west. Now, MISO at the time was importing 13,000 megawatts of power, again, across these same MVP lines that were built primarily for renewable deliveries from western MISO to eastern MISO. Transmission is -- enables and defines markets and is a real benefit for resiliency in extreme weather events.

On the next slide, actually shows the flows that were in and out of MISO. The top, you see the exports to SPP and how they cut off late on February 15th and early February 16th. That's when SPP was short and had to curtail load after ERCOT had already been in trouble and was curtailing load. And curtailments also occurred in MISO south. So this shows that we are a part on an interconnected network, and we need to take full advantage of the transmission system and consider what it can do, especially for resiliency-type events. Let's go forward if we can.

As I mentioned, the ANOPR is out there right now. A lot of people are working today and the next few days to get comments out. I'd encourage you to at least monitor this and be engaged. I think it's gonna have a drastic effect on how we do generation interconnection studies, how we do planning studies, how we define benefit-to-cost analysis, how we try to get more interregional and regional projects completed in advance of the need of the resource mix so that we could actually enable the cheapest and best resources to get into the markets and to actually facilitate the retirements of some of these old dirtier units that seem to be a challenge for a lot of reasons. Let's go forward.

So I'd like to talk about the grid impacts over the next 10 minutes, and the specific issues in this hearing. So thank you. Let's go forward.

Transmission assumptions are critical. As I said, transmission defines and enables markets, provides lots of flexibility through increased connectivity and options that you just don't get from other power-generation resources or demand-response resources.

A study by Brattle was done. It looked at Duke's solar integration service charge, noting that -- the inflexibility to the gas resources in

Duke and how that affected the load-falling capability. I would encourage Duke to think about what transmission might be able to do to help with some ancillary services and help its system become more flexible and to get access to cheaper, cleaner resources, maybe external to the system, and, at the same time, facilitate exports off system when Duke has excess and the other systems need help. Because we've certainly seen that systems need to lean on each other more and more with extreme weather. Let's go forward, please.

In the grid strategies report, I just want to clarify something. Duke misconstrued a statement that we did not advocate least-cost planning, and that's not true. I'm a big fan of least-cost planning, especially if you want to maximize the net benefits to consumers and have least regrets. Hopefully, that is the least-cost planning scenario, so just wanted to clarify that quickly. Let's go forward.

Transmission is lumpy. And we have seen that and we've heard about that. There is tremendous economies of scope and scale of transmission. I would encourage Duke to consider maybe potentially rightsizing or upsizing some of their 230 kV circuits to get 500 kV capability, especially if these facilities are adjacent to zones where they know -- that are prime candidates for solar development down the road or helping to integrate offshore wind you know, 5, 10, 15 years down the road. It takes so long to build new transmission, we have to find ways to take advantage of the existing system, especially the rights-of-ways. Those are critically important. Let's go forward.

The -- I'm impressed by the North Carolina Transmission Planning Collaborative report. I'm glad to see the findings. There are a lot of places in that report where you could inject hundreds of megawatts of offshore wind at tremendously low prices, in my opinion, with very, very modern upgrades, even up to 1,000-megawatt scale.

Now, granted, some of those facilities, especially in northeast North Carolina, that are gonna have to be coordinated with Duke or with -- I'm sorry, Dominion, clearly, you need some joint planning to capitalize on the joint benefits of major transmission upgrades to integrate offshore wind. There are benefits of injecting, you know, 2- to 3- to 5,000 megawatts into the system, especially if you get up to the higher voltages. But you're gonna have to deal with wheeling charges, as mentioned by others, as well as the effective system upgrades. So you have to plan these systems together, and I'm glad to see that that's the direction Duke's been going. Let's go forward.

Improved collaborative plan I think is really a key success factor, and that's being shown in the North Carolina Transmission Planning Collaborative with the Southeast Wind Coalition scenarios. I'm looking forward to seeing those results, and I hope Duke and Dominion can continue to work together to find the best solution for everybody for onshore and offshore transmission expansion, to take full advantage of that high-quality resource off the North Carolina backs. Let's go forward.

This is just a little bit more on the same study. One of the things I wanted to compliment Duke on was the upgrades. You know, you are trying to optimize the system you have and then reconductor that system and then rebuild it before you build new transmission lines. I think that's a great practical approach. Although, I do recommend that we look long-term and really understand what we need for the system long-term, based on reasonable expectations, as I noted in my comments on the ANOPR. Let's go forward, please.

Proactive planning studies reduce costs. And here's an example from PJM where they looked at the cost -- and PJM's using cluster studies now, like most people are. I'm glad to hear that Duke is moving forward from a sequential serial processing to cluster approach. That's gonna be a great -- a much better, faster solution of lower cost to the GI projects.

But PJM has looked at offshore wind development. And if you look at traditional clusters and add up the cost to integrate about 15 and a half gigawatts of offshore wind at PJM, you got about $6.4 billion of cost, which is about $400 a kilowatt, and that's based on the traditional approach.

Now, on the next slide, PJM decided to

look at this proactively, and they found that they could integrate 17 gigawatts of offshore wind, not looking incrementally at one-off GI leads and network upgrades assigned to specific projects one at a time, but looking at them in aggregate, and they found that the cost to integrate 17 gigawatts, if it was optimal, if it was proactive, and looked at all the benefits to all the generators and how they interact, that it would only be $3.2 billion, less than $188 a kilowatt. So the cost was half, if you would look proactively and long-term, and I think that's really important. I'd encourage Duke and Dominion and its neighbors to continue to do joint planning and long-term together. Even get out the 15- and 20-year models. I know there is a lot of uncertainty, but there is also a lot of value in having transmission that can facilitate renewable integrations. We see that in Nevada with the Greenlink projects. We see that out in Colorado with the clean power pathway project that Public Service Colorado's building to get ahead of the curve, to facilitate renewable integration at scale with the highest quality renewables becoming part of their fleet sooner rather than later. So let's move forward a few more slides.

In conclusion, you can see that the PJM study shows that the reliability upgrades necessary for offshore wind to meet public policy goals provide substantial benefits to the footprint and even lower customer cost. So that's a win/win. We need to find a way to do that, get that into our processes. Let's go forward.

One of the things that I'd like to stress is the need to take full advantage of the aging infrastructure. And decisions are being made today to replace a lot of old lines that were built in the '50s, '60s, and '70s, and we've got to find a way to leverage that in our long-range plans. And again, the ACEG report noted there is a good way to get some insights into what we might do going forward. So let's go forward.

I want to push my way through this. I apologize for going so fast. I do think that Duke can show a little more rigor in their analysis and assumptions. They mention that and how they are trying to refine the processes, and that -- the analysis for the offshore wind scenarios that are in the works. I encourage that. But coordinated studies are so important. You've got to do this if we are going to get to a co-optimized generation and transmission system. And electricity cost to consumers, as well as the risk, can be reduced if we do proactive scenario-based multi-value and portfolio-based planning studies. That's very different than doing GI over here and transmission planning over there. Cost allocations differ between each approach, because we know that a reliability project provides economic benefits and vice versa. Let's go forward. As well as resiliency benefits lately.

I think, you know, this is a little bit more depth about the coal retirements and the pockets of available transmission. There are tools out there, and Duke can conduct these of find out how much capacity is available when, to actually facilitate quicker interconnections for renewable projects. Let's go forward. Thank you.

One of the biggest things -- and I see this in a lot of forums -- is transmission is an afterthought when it comes to IRPs, and I think that's not serving us very well. Transmission has so much value it can provide, in terms of capabilities and optionality, that it has to be considered as one of the key components of any integrated resource planning effort. I know that's hard to do, given current processes and tariff requirements, but I think we need to find a way to do that and get that transmission planning into the IRP processes. Let's go forward.

I want to wrap this up. There is a lot of details in here about the assumptions. You know, the cost to import 10 gigawatts of offshore wind was, what, $8 billion? I mean, it's a lot of money. And they just assumed it was twice the cost to add -- to import 5 gigawatts. I think there is tremendous economies to scale that need to be captured. Little bit sharpening of the pencil will help a lot. Let's go forward.

You can see the reference to the data request, that there really wasn't much effort by Duke to look at what could happen at the end of life in corridors. I think this is really important and needs to be part of the planning process at Duke and with its neighbors as it goes forward. Let's go forward.

The failure to capture benefits of

optimized and least-cost planning. We don't see that, you know, especially beyond the first two gigawatts of developments in here. It's in the same cost per kilowatt of installation and integration in terms of network upgrades. I think that's overly simplistic, and we need to refine the analysis and sharpen the pencil as I mentioned before. Let's go forward.

I want to wrap this up. Modeling by Synapse suggests that, you know, significantly more energy -- clean energy developments with lower cost could be integrated into the resource plans. And then, as a result, that Duke could get the economies of scale for a more efficient and effective bulk system and projects. Duke didn't consider these at all from what I can tell. I encourage them to do that going forward. Let's go forward to the next slide, and we're gonna wrap this up.

That's where I'm at. I appreciate your time. I'm sorry I rushed through this so quickly.

COMMISSIONER CLODFELTER: Mr. Caspary, we understand the constraints you are operating under, and we appreciate your efficiency. You got through an awful lot of material. Thank you for that.

Mr. McDowell, I understand you don't have any questions; is that correct?

MR. McDOWELL: That's correct.

COMMISSIONER CLODFELTER: All right. Let's go to Commissioners, and I think Commissioner Gray, you're first up.

COMMISSIONER GRAY: I have no questions, but it was a great presentation, even quick, though.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: No questions. Thank you.

COMMISSIONER CLODFELTER: Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions. Thank you.

COMMISSIONER CLODFELTER: Commissioner Hughes?

COMMISSIONER HUGHES: No questions as well. Thanks.

COMMISSIONER CLODFELTER:

Commissioner McKissick?

COMMISSIONER McKISSICK: No questions.

COMMISSIONER CLODFELTER: All right. Mr. Caspary, you can't get off without at least one question. Is there any system, RTO or ISO or any independent system, that's in the United States that is making extensive use of any of the gas technologies that we could take a look at as a case study?

MR. CASPARY: Not yet. There are pockets of them being deployed, primarily as pilot projects. They are getting more and more attention, and I would expect that, if you looked at what's going -- it's hard for me to even keep up with what's going on with dynamic line rating companies, because there are so many installations out there right now. There is actually a big project at PJM that was put in by PPL to basically offset a market efficiency project, to actually put in dynamic line ratings in PJM to actually understand the line rating, and not necessarily rebuild or build an adjacent facility because that line is shown to be overloaded. And I think the results are going to be very enlightening, in terms of helping people understand that maybe the assumptions that are used in planning models for static line ratings are too conservative, and we need to maybe loosen them up a little bit and be more realistic. And there is other technologies too that are being -- a lot of case studies are out there, and smart wires are installed in a lot of devices on the systems. Not necessarily in the U.S. Mostly in the UK, Australia, and around the world where they have a different incentive structure for utilities to do that. Thank you. I appreciate the questions and look forward to any follow-up online -- off line too.

COMMISSIONER CLODFELTER: Thank you. You have given us a number of topics. We know how to find you to get follow-up.

Yes, Chair Mitchell?

CHAIR MITCHELL: Commissioner Clodfelter, one question. You know, the -- you point out, sort of, what Duke's failures with respect to its -- the transmission analysis included in its IRP, and so just two things. I mean, I think in the discussion today with Duke they've -- they -- there seems to be some agreement between you-all that some changes in the transmission planning process should occur, you know. So I kind of -- I see -- I think I heard them headed in -- or at least maybe partially headed in the direction that you suggest they need to go. Am I wrong about that?

MR. CASPARY: No, I think you're right. Thank you. Yeah. It's a question of timing and a sense of urgency, and do you wait for FERC ANOPR comments and then debate about whether you need to change the planning process or the GI process or do you get ahead of that curve --

CHAIR MITCHELL: Understood.

MR. CASPARY: -- and do it because it's the right thing to do? Hopefully, they are gonna be more proactive and take advantage of capabilities that exist today that just aren't in the current tariffs and other processes. Thank you.

CHAIR MITCHELL: Last question for you is, to -- just for our own edification, is there a jurisdiction -- is there a state right now that is utilizing some of these transmission planning processes that you advocate?

MR. CASPARY: Yeah. And you've heard this before. Colorado, I think, is the leader, Nevada is the leader. They are building transmission proactively to actually lower the cost of actual approved capacity additions, to facilitate earlier retirements of fossil fleet and accelerate the integration of renewables.

CHAIR MITCHELL: And do you know if those processes are being conducted pursuant to state law or is that just pursuant to existing authority that those Commissions have?

MR. CASPARY: I think there have been law changes, at least in Colorado, that have facilitated that, yes.

CHAIR MITCHELL: Okay. Thank you for that. I appreciate it. Nothing further.

COMMISSIONER CLODFELTER: Mr. Caspary, thank you for being with us today. All right. We -- let me check in on something, and this is a proposal I am going to make. Mr. Josey, where are you? There you are. We have got the Attorney General's presentation, and they have a third-party presenter, so I'm going to proceed in that order and take their presentation next. Your presenters are all on staff, correct?

MR. JOSEY: Yes. We only have one presenter, it's Mr. Metz, and I believe his presentation is only about three minutes, so.

COMMISSIONER CLODFELTER: Okay. Well, then, that changes what I was going to propose. I was going to suggest we sandwich you in at some other point in our agenda where we've got you just across the hall and we could call you over and get you in, but if you've only got about three minutes, Ms. Force, let's plow ahead and let's take your presentation next, Ms. Force.

MS. FORCE: Thank you, Commissioner. I'd just like to introduce Edward Burgess again from Strategen and turn it over to him.

COMMISSIONER CLODFELTER: Welcome back, Mr. Burgess.

MR. BURGESS: Thank you, Commissioners. I'm gonna attempt to call up my slides here, if I can have access to the shared screen. Okay. Can you-all see and hear this? Great. Thank you.

I will skip my introduction, since I introduced myself last week, and just jump in to topic 3 here on grid impacts. You know, two main, kind of, issues that I wanted to cover. First of all, that, you know, from the -- you know, our assessment and the Attorney General's review of the IRP, you know, we felt that there would need to be more analysis and transparency going forward of some of the very significant transmission and distribution investments that Duke is planning. And I'll give an example of that, you know, relating to the transmission for coal retirements.

And then second, you know, we wanted to just touch on the fact that increased understanding of Duke's grid interactions is going to be increasingly important going forward for a variety of reasons, and so, you know, that's a really fundamental part of resource planning, and we have a few recommendations on that front.

So just to start, you know, one of the reasons we're interested in more transparency on these transmission plans is just the sheer, sort of, scale of the investment that we're talking about here. You know, Duke has been presenting to its investors that it plans to invest about $17 billion over the next five years in T&D, you know, not

15 -- 10 or 15 years, but -- so from a planning perspective, we are really rapidly entering this execution stage, and should be able to hopefully drill into some of the specifics of what's being planned.

You know, and in particular, Duke's made a lot of claims about certain transmission investments that are needed to retire some of its coal plants, and I want to dive into those in particular. And I think it's especially worth noting that, you know, these costs associated with the coal plant retirements are actually, you know, wind up delaying the retirement of certain coal plants in Duke's economic assessment. You know, it's sequential peaker analysis. So in order to avoid incurring those costs, you know, we're seeing delayed plant retirements. And so this -- you know, it's really important, I think, to gain a full understanding of what these transmission costs are.

You know, so based upon our review, we think there is a lot of unanswered questions about the transmission needs for these coal retirements based on the public and confidential information

Duke provided. You know, some of the details Duke provided on its transmission analysis were confidential, so out of abundance of caution, the Attorney General's marked these slides confidential. Without going into the specific details I --

COMMISSIONER CLODFELTER: Mr. Burgess, I'm sorry to interrupt you, but at least on my screen, the confidential information is appearing. So you may want to check your slide -- your screen sharing and your slide presentation, because at least I'm able to see the confidential information and also your marginal comments. So you may want to adjust your screen sharing now.

MR. BURGESS: I'm sorry, I don't --

COMMISSIONER CLODFELTER: No. Now it's up there for everybody.

MR. BREITSCHWERDT: Commissioner Clodfelter, this is Brett Breitschwerdt at Duke. I do believe the information that is identified is the unredacted version -- or excuse me, the redacted version that doesn't show the confidential. Mr. Burgess, it does seem that your speaker's notes and the next slide are presented on the screen. So perhaps you're sharing the wrong screen, but the information presented is not confidential.

MR. BURGESS: I see. Let me see if I can adjust which screen is being shown. Is that -- I'm not sure if I can do that in this.

MS. FORCE: Just to clarify, I think the following slide appears to the right and it is not confidential.

COMMISSIONER CLODFELTER: Thank you for cleaning me up on that. I thought that was the confidential version of the redacted slide.

MS. FORCE: It is not. It's a little confusing because it was showing the next slide. Now the notes are not there. So thank you.

MR. BURGESS: Are the notes still showing now or is it --

COMMISSIONER CLODFELTER: They are not.

MR. BURGESS: Okay. I don't think there was any confidential information in the notes either, so I don't think there would be an issue. In any case -- okay.

Just to pick back up, you know, without going into the specifics, I do want to just talk about some of these concerns in general terms. You know, for more detail, you can refer to the initial comments the Attorney General filed on page 7 of the confidential attachment as well as the confidential version of these slides, which puts some more meat on the bones of those initial comments. And yes, these slides should be redacted, you know, that I'm showing here now, but you-all should have copies of the those confidential slides if you'd like to follow along.

So some of the general concerns. Some of the reliability needs initially identified by Duke didn't make much sense to us on a technical level as being related to specific plant retirements. In fact, they seemed to be more related to certain global reliability issues that wouldn't be tied to an individual generator. And, you know, even when we considered more localized issues, you know, there have been periods of time in the recent past where some of these plants have been offline for extended periods of time, and you know, presumably the system still operated reliably even without these upgrades in question. And so, you know, that just gives us some pause about, you know, what specifically are the concerns here about transmission and reliability? Can we, sort of, get a little more specific about what those needs are? And, you know, what we later learned is that Duke has done some transmission studies to look at these retirements. And, you know, when we looked into these studies, we did have, you know, additional questions and concerns about what they were showing, including concerns about potential double-counting of certain transmission costs. You know, seeing the exact same, you know, transmission element upgrade identified at multiple plants that were retiring. You know, studies used to identify the upgrades appeared to have certain assumptions that weren't aligned with the IRP. You know, we had also some concerns that not all of the likely mitigation factors were being properly examined. You know, for example, the assumptions around onsite generation as a mitigation factor.

You know, keep in mind that these were -- you know, these studies were driving determinations about coal retirement dates, and so, you know, some of these issues, I think, play into what we talked about last week.

So, ultimately, you know, we recommended that an independent analysis of the transmission needs to be conducted prior to the next IRP cycle in 2022 to look closely at what those transmission upgrades are for the retirements. And let's see, I will move to the next slide.

You know, fundamentally, we thought that the Commission intervenors maybe didn't have quite the solid fact basis it needed to assess some of these claims about the retirements, and that's one reason we recommended initially a hearing in this matter, but, you know, in lieu of that, we think that this independent analysis of the transmission needs could be a good next step.

Okay. I want to shift topics here and talk a little bit about grid interaction with neighboring systems. As I mentioned, and has been discussed here today, you know, this is key for planning issues in a variety of capacities. So, you know, a few of them include how we think about Duke's winter reliability needs, and everyone is to be aware of what occurred in Texas this February with the outages. And, you know, I think it's important to recognize that one reason that they were in that situation was because the Texas grid essentially functions as an island and, you know, didn't have the ability to interact with its neighbors in the same way that other regions did. And so, while, you know, I think Duke makes a good point about we don't want to necessarily depend upon neighboring regions exclusively for reliability needs and there are some more coordination that needs to go on there, I think having greater import and export capability can really be thought of as an insurance policy under these kind of extreme grid stress conditions and, you know, the fact that SPP and MISO, while they had a lot of similar conditions as Texas, didn't face nearly the same catastrophic outages, partly because they were able to interact with each other and with their neighbors to relieve some of that stress.

In addition, you know, looking at the import and export capability can help potentially unlock more firm contracts, you know, relying on cheaper resources in other regions rather than having to build our own, you know, locally, and could provide both economic benefits and provide that, sort of, more dependable support with neighboring systems through those firm contracts, rather than the unfirm resources that Duke was concerned about.

Looking at just the total overall peak megawatt needs and the resulting system cost in Duke's resource adequacy study included an island scenario where they looked at just what they would have to do to serve their need locally, and that increased their reserve margins by over 6 percent. And I think Duke spoke to that, but, of course, you know, the reverse should also be true, and if we have greater imports and exports, that could potentially lower the reserve margins. And so, you know, one recommendation would be for those future RA studies to look at scenarios with a relaxed import constraint, you know, especially for PJM, which, you know, is one of the regions where there was some transmission constraints. And even if that's just for informational purposes and not necessarily to set the reserve margin target, I think it would be useful just to understand how much benefit we could get from that greater neighbor interaction.

It also impacts capacity value solar. Some of the neighboring systems, PJM, Southern, may have their summer peaking and may have excess capacity in winter, so there could be some diversity of loads and resources that complement each other in that situation, and that would help alleviate Duke's winter peaking needs and greater interaction of these systems that could potentially shift that -- you know, the capacity needs back from winter towards summer as it was in the past. And, you know, that's when, of course, solar was more plentiful and may be able to provide a greater contribution to the system reliability.

I think, you know, as we think about the planning, you know, what are some concrete steps to sort of think about planning in a more regional basis and looking at how we can do that in future IRPs. You know, just getting a more solid understanding of, you know, how Duke's interacting with its neighbors, and identifying the precise import and export constraints with the neighboring systems, some of which was provided in the RA studies in the IRP. But I think that more could be done to, sort of, continue evolving that understanding over time, identifying how those historic flows across each interface have been working, and maybe even some kind of dashboard to illustrate this. You know, identifying what are the actual, you know, constraints that are on those interfaces. Is there a specific transmission element that's, you know, causing issues? And maybe that's a small upgrade. Maybe it's a large upgrade, but maybe it's small and could really unlock more of that interaction. Is it just some sort of a rule of thumb that system operators use because that's how they've historically operated? Is it some kind of a legacy, you know, firm contract on a line that's, you know, not really reflective of how it's physically being used, but just how contractually the arrangements have been made? And is there something that you could do to, sort of, tap into unused capacity on that transmission system?

And so, you know, once those things have been identified, we can identify steps to maybe alleviate those constraints with specific upgrades or perhaps some of the solutions that Mr. Caspary was talking about with dynamic line readings and other non-wire solutions, and we can look at those.

And then, you know, next, identifying the resulting increase in the capacity along those lines if the upgrades were taken. And then that could, you know, form a basis of looking at these different scenarios where there is higher imports or exports and cases to be studied in the IRP. A lot of other regions -- I'm familiar with regions in the West where they do actually study -- you know, for these high-renewable-energy scenarios, look at different import and export constraints and, you know, to see what is the actual benefit that we could achieve by increasing that amount of flow and diversity across the region.

We talked about, too, the co-optimizing between generation and transmission planning. This is -- will always be a tough, sort of, chicken-and-egg problem, in terms of, do you plan generation first and then transmission or vice versa? I will point out that there have been recent studies that have actually taken the steps to try to co-optimize generation and transmission across large regions of the grid, and even with some IRPs as well. And some of the ones that, you know, I'm familiar with -- and I think there are many others, including, the Western Electricity Coordinating Council through their TEPPC committee undertook this effort almost a decade ago, I think, and developed a tool to co-optimize this. More recently, you know, the National Renewable Energy Lab has conducted a sort of country-wide study to look at this issue too. And these are complex studies, but, you know, they really provide a wealth of insights and information if they are done well, and so, you know, one thought that the Commission could explore might be initiating partnerships with, you know, either National Lab or other institutions that have the capabilities to conduct these kind of studies and do so for the Carolina's region with the goal being provide guidance on what that sort of optimal transmission investment that, you know, Duke and other utilities in the region could be making to achieve the clean energy goals that we're all seeking. And so, you know, part of the Commission's role might be making sure all the necessary data and information is provided to the entities that are collaborating and working on these studies.

And so with that, I will stop it there and leave just a few minutes for additional questions, or if we want to turn to the next presenter in the next few minutes here.

COMMISSIONER CLODFELTER: Thank you, Mr. Burgess. Are there questions for Mr. Burgess? And we will begin with Commissioner Gray.

COMMISSIONER GRAY: No questions.

COMMISSIONER CLODFELTER: All right. Chair Mitchell?

CHAIR MITCHELL: I do have a question. Mr. Burgess, if you go back to the last slide of your presentation, you discuss the Commission's initiating a partnership with one of the Labs to conduct a study for the Carolinas. Talk some about what specifically -- what specific type of information do we need to gather in this -- what would we be looking at here?

MR. BURGESS: Yeah. I think what really -- there is, I think, a couple of things that would hopefully emerge from this kind of a study. One would be to try to look at, again, this, sort of, how do we co-optimize generation and transmission together, right, rather than sort of studying one and then the other in a silo? And this provides an opportunity, I think, to take, you know, a more advanced approach to system planning, leveraging, I think, some of the, you know, computing capabilities that these institutions have, because, you know, it can become a very intensive exercise on that front.

But then, you know, the results would be to look at scenarios with different generation mixes that we want to achieve, you know, whether that's a certain amount of renewable energy or clean energy, and then the transmission that goes along with that, with the goal of really being able to identify, okay, what are those key, you know, backbone, kind of, transmission projects that we want to invest in to allow that scenario to occur cost-effectively? Because a lot of transmission planning occurs in a much more localized fashion. You don't necessarily see the full benefits of these kind of regional projects that could occur, and, you know, there's been attempts to try to get -- overcome this through -- in the past with things like third-quarter 1,000, which hasn't really been as effective, I think, as a lot of folks hoped at the outset. But to really try to do more regional -- interregional planning to say, here's some really critical backbone lines that would enable a lot of potential resources to come under the system in a cost-effective manner. And, you know, we have studied this in a way that we know this is really more of an optimal approach than, sort of, a patchwork that you might see, especially in a place like the Southeast where you have individual balancing authorities and utilities kind of operating in a more islanded fashion. You know, how do we get them together and coordinate planning more regionally.

CHAIR MITCHELL: Okay. So your recommendation is more focused on regional or, sort of, BA-to-BA coordination as opposed to within the BAs?

MR. BURGESS: Yeah. I think that's probably right. I think it would be -- I think these kind of efforts would, yeah, be more geared towards that sort of regional look and -- rather than, like, within the BA.

CHAIR MITCHELL: Okay. All right. Thank you very much. Nothing further for me.

COMMISSIONER CLODFELTER: Thank you. Commissioner Duffley?

COMMISSIONER DUFFLEY: No questions. Thank you.

COMMISSIONER CLODFELTER: All right. Commissioner Hughes?

COMMISSIONER HUGHES: No questions.

COMMISSIONER CLODFELTER: Fine. I -- Commissioner McKissick, I can't see you on the screen. You may be gone. I think he is gone by now.

Thank you, Mr. Burgess. I do not have any questions for you today. I appreciate your presentation.

MR. BURGESS: Thank you.

COMMISSIONER CLODFELTER: Mr. Josey, let's see if you can get Mr. Metz in -- you said three minutes. Let's see what happens here. This will be interesting.

MR. JOSEY: Sure. Absolutely. And just before he gets going, I would just like to say that if the Commission would like to meet with the Public Staff at a later date, informally or formally, we are happy to do so. And if we can't get to the questions or discussion that Mr. Metz's presentation may bring up, then we are happy to answer those questions at a later date.

COMMISSIONER CLODFELTER: We'll see what we can do. Proceed.

MR. JOSEY: Thank you.

MR. METZ: My name is Dustin Metz. I'm an engineer with the Public Staff's energy division. I have a couple of modified topics I'd just like to convey to the Commission. (Sound failure.)

(Court reporter interruption due to sound failure.)

COMMISSIONER CLODFELTER: Mr. Metz, your audio is a little bubbly. Sounds like you're gurgling a little bit.

MR. METZ: Can you hear me now?

COMMISSIONER CLODFELTER: Joann?

COURT REPORTER: That's a little better.

MR. METZ: I have a couple of modified topics I would like to convey to the Commission. The natural retirement of aging assets and transition to a new generation fleet or portfolio, either with accelerated retirement or not, has and will need to be considered for transmission planning cost and even timing. The topic of area of concern of large-scale policy portfolios may require even more time requirements than what we were accustomed to for general IRP planning purposes.

My second topic, the Public Staff submitted a transmission modeling request to the planning collaborative. The intent of the policy request was to think outside the box and look at a what-if scenario while maintaining a diverse generation portfolio.

What would the transmission system tomorrow look like with a mix of portfolios? Is it significantly different than what we have now or will it be more of the same? This request blended multiple independent evaluations and is attempting to look at a total impact or wholistic impact. Perhaps a blended approach can find synergies and leverage savings, or perhaps it will find other reliability impacts that we have not considered or identified. It is a more proactive approach to inform potential policy decisions and enable further evaluation of resource optimization in the

Carolinas while trying to strive for reasonable cost for system users.

How do we balance 10- to 15-year transmission planning versus a 60-year transmission life? We do it by planning and modeling. By running a series of different generation injection scenarios and potential procurement of resources in dedicated areas via solicitation may be ways to mitigate some of the risks and concerns that were brought forward today.

That completes my two-minute presentation.

COMMISSIONER CLODFELTER: Thank you, Mr. Metz. I'm just gonna ask for Commissioners to raise their hands if they have any questions they want to ask Mr. Metz.

(No response.)

COMMISSIONER CLODFELTER: All right. Mr. Metz, I want to thank you on behalf -- Commissioner Duffley?

COMMISSIONER DUFFLEY: I think Chair Mitchell had a question.

CHAIR MITCHELL: Go ahead, Commissioner Duffley.

COMMISSIONER CLODFELTER: Oh, I'm sorry.

CHAIR MITCHELL: No. Go -- let Commissioner Duffley go and then I'll ask mine.

COMMISSIONER DUFFLEY: No, no. I was just raising my hand so he would catch your question.

COMMISSIONER CLODFELTER: Okay. Chair Mitchell.

CHAIR MITCHELL: Mr. Metz, just so I'm clear, are you-all endorsing -- looking at transmission in a different way? Are you saying that we could do transmission planning in a way that identifies synergies and cost-effective solutions and maybe even addresses reliability concerns that we were aware of or maybe not aware of in a way that current process doesn't?

MR. METZ: Yes. And it's really leveraging -- the pieces of the planning collaborative have already been -- already have been completed over the years. Based upon being a part of the planning collaborative for about six years, it's not to throw shade at the planning collaborative to do a great job, but my observation has been we have looked at wheeling 2,000 megawatts through the system -- I'm oversimplifying this -- we've looked at wind impacts, we've looked at these individual one-off scenarios. While they are important, this took a different approach and said, okay, I looked at the IRP, I looked at the system needs and said what if we did a little bit of everything, what would the transmission system look like? Let's blend all that together. Perhaps that's a different way to start evaluating potential policy changes or transmission planning.

CHAIR MITCHELL: So how do we get there?

MR. METZ: So hopefully through the planning collaborative we will be able to see the results of this one. And I think, as Mr. Byrd has stated, potentially at the end of the year or maybe even into next year we will be able to evaluate from a technical evaluation to see what the results provided us, allow that to inform, going into 2022 IRP, of what things we may have to do differently or things that we may have to modify going forward. So it is an incremental step towards evaluation that's already ongoing.

CHAIR MITCHELL: Okay. All right. Thank you, Mr. Metz. Nothing further for me.

COMMISSIONER CLODFELTER: Anyone else?

(No response.)

COMMISSIONER CLODFELTER: Mr. Metz, following up on that, I want to commend the Public Staff for making that request for the public policy study. You are way ahead of me. I had planned to ask Mr. Byrd this morning why the collaborative was not modeling and studying the alternative resource portfolios in the IRP, only to learn that the Public Staff had already made exactly that request and that that work was underway by the collaborative. So once again, you are ahead of us on this, and I commend you for getting that out there. Thank you. That was -- I think that's going to be a very, very useful exercise. Thank you.

All right. Those are all the presentations we had. Mr. Jirak and Mr. Breitschwerdt, I had said that I would give you some time Friday afternoon for a response on coal retirements and you wanted to defer. I am, unfortunately, not able to give you that time right now. So I think we are going to have to rest on the presentations as they stand, given the time we have got now.

So I want to -- on behalf of all the Commissioners, I want to thank all the presenters and counsel and the parties. These have been uniformly very high-quality, exceptional high-quality presentations. I think they stimulated an awful lot of good analysis and good thought and good questions for all of us to, sort of, explore and think about. You've equipped us very, very well through these presentations, I think, to begin thinking about some of the questions that we're going to have to address with respect to the 2020 IRPs, the 2022 IRPs, and, if it should happen to pass into law, the questions that we will have to address under the current legislation that's moving through the General Assembly.

I couldn't have asked for better. And again, I know I speak for my colleagues when I say thank you very much. This has been some really very, very good work. So anything further before we conclude the technical conference?

MR. BREITSCHWERDT: Nothing from Duke. Thank you.

COMMISSIONER CLODFELTER: Again, thank you all and enjoy the rest of the day, or continue with your work for the rest of the day as may be appropriate.

(The technical conference concluded at 12:05 p.m. on Wednesday, October 6, 2021.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

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

This the 15th day of October, 2021.

JOANN BUNZE, RPR

Notary Public #200707300112