PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, November 2, 2022

TIME: 1:00 p.m. - 4:09 p.m.

DOCKET NO: E-7, Sub 1276

BEFORE: Commissioner Kimberly W. Duffley, Presiding

Chair Charlotte A. Mitchell

Commissioner ToNola D. Brown-Bland

Commissioner Daniel G. Clodfelter

Commissioner Jeffrey A. Hughes

Commissioner Floyd B. McKissick, Jr.

Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Carolinas, LLC's Request to

Initiate Technical Conference

Pursuant to Commission Rule R1-17B(c)

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P R O C E E D I N G S

COMMISSIONER DUFFLEY: Good afternoon. Let's go on the record, please. I am Kimberly W. Duffley, Commissioner at the North Carolina Utilities Commission, and with me are Chair Charlotte A. Mitchell and Commissioners ToNola D. Brown-Bland, Floyd B. McKissick, Jeffrey A. Hughes, and Karen M. Kemerait.

I now call to order Docket Number E-7, Sub 1276, which is captioned In the Matter of Application of Duke Energy Carolinas for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation.

North Carolina General Statute §62-133.16 authorized performance-based regulation, or PBR, for electric public utilities. Pursuant to statutory directive on February 10, 2022, the Commission issued an order adopting Commission Rule R1-17(b) to implement this statute.

On September 8, 2022, Duke Energy Carolinas, or DEC, filed a letter with the Commission indicating its intent to file a general rate case application that includes a performance-based regulation application, or PBR application, as authorized under North Carolina General Statute §62-133.16, with the PBR application targeted for filing no earlier than January 6, 2022.

DEC also requested, pursuant to Rule R1-17(b), that the Commission initiate a technical conference regarding the projected transmission and distribution projects to be included in DEC's PBR application.

On September 14, 2022, the Commission issued its order scheduling technical conference and setting procedures for technical conference, scheduling the technical conference to be held on this date, November 2, 2022, beginning at 1:00. The purpose of this technical conference, which is required by statute, is to allow DEC to present information regarding its projected transmission and distribution expenditures.

The Commission's September 14th order permits interested parties to intervene and to provide comment on DEC's filing. In addition, the Commission permits interested parties an opportunity for a presentation today, subject to advanced notice requirement.

Upon the filing of timely motions, the following parties have petitioned to intervene and have been allowed to intervene in this proceeding: The Carolina Industry Group for Fair Utility Rates III, or CIGFUR III; Carolina Utility Customer Association, or CUCA; North Carolina Justice Center, North Carolina Housing Coalition, and the Southern Alliance for Clean Energy, or SACE, and Natural Resource Defense Counsel, or NRDC, collectively NCJC, et al.; North Carolina Sustainable Energy Association, or NCSEA; Haywood EMC; Blue Ridge EMC; Rutherford EMC; and Piedmont EMC. The Public Staff, which represents the using and consuming public in matters before the Commission, will participate in the technical conference as well.

On October 19, 2022, DEC filed its projected T&D expenditures and parties may file written comments on DEC's T&D filing through today, November 2, 2022. And that brings us to today.

It is my understanding that the only presentation today will be from DEC. There will be no cross-examination of DEC's witnesses, per the terms of the statute, but Commissioners will be able to -- permitted to ask questions of DEC's witnesses. There will be no questions taken on Commission questions.

This technical conference is being transcribed, and the transcript will be filed in the docket as soon as it's available.

Before we begin, I would like the parties to identify themselves for purposes of the record, and we will start with DEC.

MR. JEFFRIES: Thank you, Commissioner Duffley, Chair Mitchell, members of the Commission. My name is Jim Jeffries. I'm with the law firm of McGuireWoods. I'm here on behalf of Duke Energy Carolinas today. And with me is my co-counsel, Mr. Josh Combs, who is with the law firm of Troutman and Pepper, and who has been admitted previously pro hac vice for this proceeding by the Commission order issued on October 3rd. Thank you.

COMMISSIONER DUFFLEY: Okay. Good morning, Mr. Jeffries, Mr. Combs.

MR. COMBS: Good morning.

COMMISSIONER DUFFLEY: Afternoon. Good afternoon.

MS. LUHR: Nadia Luhr with the Public

Staff, on behalf of the using and consuming public.

COMMISSIONER DUFFLEY: Good afternoon, Ms. Luhr.

MS. JONES: Good afternoon. Taylor Jones, regulatory counsel for the North Carolina Sustainable Energy Association.

COMMISSIONER DUFFLEY: Good afternoon, Ms. Jones.

MS. CRESS: Good afternoon, Presiding Commissioner Duffley and Commissioners. Christina Cress with the Law Firm of Bailey and Dixon here on behalf of CIGFUR III, Blue Ridge EMC. Haywood EMC, Rutherford EMC, and Piedmont EMC. Thank you.

COMMISSIONER DUFFLEY: Thank you, Ms. Cress. Anyone else?

(No response.)

COMMISSIONER DUFFLEY: Okay. Before we begin, are there any preliminary matters?

(No response.)

COMMISSIONER DUFFLEY: Okay. We'll go ahead and get started.

Mr. Jeffries?

MR. JEFFRIES: Thank you, Commissioner

Duffley. We have three presenters for DEC present today, two of whom you have seen previously at another MYRP technical conference, but those individuals are Mr. Brent Guyton, who is to your right. He is the director of distribution asset management for Duke Energy. Next to him is Mr. Dan Maley, who is the director of transmission compliance. And then next to Mr. Maley is Ms. Laurel Meeks, who is the director of renewable business development for Duke Energy.

And with that, I'll turn this over to Mr. Guyton.

MR. GUYTON: All right. Good afternoon, and thank you to all attendees who have joined the technical conference today, as we know your time is valuable. We believe you will find today's session informative. My name is Brent Guyton. I'm the director of distribution asset management for Duke Energy here in the Carolinas.

For today's technical conference, we have three subject matter experts who will be speaking on the distribution, transmission, and energy storage investments identified in the MYPR. I will be our first speaker, followed by Dan Maley, director of transmission compliance coordination, and then Laurel Meeks, director of renewable business development will wrap up our presentation.

We will spend the next couple of hours sharing information on the discrete and identifiable distribution, transmission, and energy storage investments identified by DEC's MYRP.

Over the course of the technical conference, we will provide an overview of the trends that continue to impact our industry and drive our system planning. We will also share an overview of the distribution, transmission, and energy storage projects programs that will be included in our MYRP proposal, and which were identified in the pre-technical conference documentation. These investments are necessary for the Company to both maintain and advance the grid to support the clean energy transition. In addition, we will also provide specific examples of the planned work identified in the multiyear rate plan period.

It is important to note that this presentation today is an overview of the previously submitted materials documenting the scope of our

MYRP, and it is not intended to provide detail on every program or project identified.

As a reminder, on October 19th, Duke Energy provided the following information: detailed description for each planned improvement program or project, that description included the purpose and description of the work to be completed; a summary of the expected benefits; the estimated cost -- installation cost for the planned distribution, transmission, and energy storage work.

Additionally, Duke Energy has provided a complete list of planned projects, including projected in-service dates, estimated total cost for each individual project, House Bill 951 policy considerations addressed also.

And lastly, cost-benefit analyses that list costs and benefits of each program or project, and most include a financially based CBA.

Duke Energy is actively engaged in the ongoing implementation of the federal Infrastructure Investment and Jobs Act, or IIJA, at the state and federal levels. The $1.2 trillion IIJA has $60 billion earmarked for specific needs in the power and energy sector, including meaningful funding opportunities for grid resiliency work to promote electrification and clean energy technologies.

We acknowledge these funding opportunities will be administered through an extremely competitive grant process, and Duke Energy is well positioned to aggressively pursue these opportunities.

We are participating in requests for information and discussions with federal agencies, including the Department of Energy, the Department of Transportation, and the Environmental Protection Agency. For instance, to help inform DOE's IIJA program administration, we submitted a response to the GRIP on October 14th. This RFI, along with seven of our other RFI responses, have been submitted as informational updates in the NCUC IIJA docket.

While federal agencies are making progress, they are still in the early phases of their overall IIJA implementation, with many new programs actively under development. While programs are under development the Company has defined its IIJA grant prioritization process, which has been shared with Public Staff. It includes building a disciplined prioritization framework and operating model through a partnership with an outside expert, benchmarked against industry peers. This process includes proactive grant planning, grant writing and submittal, and grant execution plans moving forward. Throughout these efforts, the team carefully reviewed grants the utility may apply for directly, as well as grants Duke Energy may support via its state and local government and other community partners.

Duke Energy's goal is to maximize the customer benefit of the grant proposals that we submit. We look forward to responding to the grid-related IIJA funding opportunity announcements, which are anticipated to be released this quarter of 2022, and we'll keep the Commission updated on the status of our efforts.

To be clear, we are pursuing IIJA funding opportunities for the benefit of our customers and will ensure that the customers receive that benefit. However, the customers -- sorry, however, the projects included in this technical conference and that will eventually be included in the MYRP requested later, are projects that benefit customers and make sense to do, regardless of whether or not IIJA funding is received.

None of the cost-benefit analyses or cost estimates submitted with our prefiled materials assume that IIJA funding is received. The Company is also working to identify a second set of projects that may only make sense to do if IIJA funding is received. No projects of this nature have been included in the technical conference materials.

The U.S. electric grid is in a complex transition. Its original design was somewhat simple and intended to power the lives of individuals in our great country with a few design assumptions in mind, such as that generation was firm and dispatchable, generation also always followed load and kept power in balance, and load at the distribution level was treated as passive load attached to the transmission system, fourth power flowed in one direction from central generation to the customer, and lastly, the grid was designed for reliability.

The mission of the electric utility grid has significantly changed over the decades. The mission used to be keep the lights on, keep the lights on, and keep the lights on. Today, the grid must still keep the lights on, but we also have to factor in other considerations. The grid must be cyber secure, it must be physically secure, it must be flexible in enabling new solutions and technologies, accessibility, economical, clean and sustainable, and above all, resilient.

Significant trends are affecting the grid that were introduced by the Company back in 2019 that are very much still present today.

Grid improvement technology has advanced over the last decade, giving utilities alternatives to traditional options. Technological advancements in renewables and DERs are growing rapidly, driving expectation for increased adoption. Threats to grid infrastructure are on the rise, including both physical and cyber threats. The impact of weather events is increasing in frequency and severity for the grid and our customers. Concentrated population growth in urban and suburban areas continues and requires new infrastructure.

Customers' expectations are evolving with a focus on reliability and new options to save money and safely access clean energy. And lastly, environmental commitments at the federal, state, local, and corporate levels, both public and private, are being made with goals for renewables, low carbon transportation, and energy efficiency.

As we shift our thinking to the future, the grid must be thought of as an enabler, one that safely integrates new grid technologies and supports expanded distributed energy resources, such as solar, wind, storage, and electric vehicles. To do this, the legacy grid must be upgraded and adapted to accommodate dynamic two-way power flows, load shifting, and greater situational awareness for our operators.

Traditional forms of grid planning are no longer adequate. Duke Energy has implemented integrated systems operations planning, or ISoP, for grid plans leveraging more and more data, like the propensity to adopt solar and purchase of an electric vehicle when planning future projects. The program's plan will use these new processes to implement tailored solutions that will be an enabling platform, essentially creating a grid that is a digital superstructure that delivers on the energy goals and requirements of our state.

As we think about the future grid and the clean energy transition, three primary objectives bubble to the top. First, grid resiliency. We must have a grid that has the ability to withstand and recover from for frequent extreme weather and other external events. We must have a grid that is more reliable if we are going to count on more variable distributed energy resources, especially at the distribution level.

Expanding renewables and DERs. We must enable the grid to meet customer demand for DERs, while maintaining safe and reliable service. And we have a bold carbon goal in North Carolina and we must prepare the grid as safely and reliably integrate increased variable distributed resources.

Also, equitable access to benefits. We must achieve a balanced outcome for customers across the entire service territory, promoting access to emerging technologies and energy solutions. And lastly, we must implement our projects in the most efficient manner possible, with an eye on customer affordability.

I will now shift to an overview of the distribution projects. I'll cover seven areas: benefits to customers, critical grid capabilities, an overview of the work streams and programs and distribution projects, our planning approach to maximize customer benefits; I'll also provide an overview of the specific MYRP project in our Triad zone, I'll also cover our methodology for our financial cost-benefit analyses, and lastly, I'll highlight the programs that make up our MYRP projects.

Before I shift to those seven areas, I want to talk briefly about how we'll be delivering the benefits to the customer and establishing and/or strengthening the critical grid capabilities that are needed. I'll explain this more as we go along, but I wanted to introduce it as we get started.

Our projects are planned for a geographically clustered set of substations. Each substation and its associated circuits, based on their specific needs, will receive selected distribution program. It's not one-size-fits-all.

And lastly, work is executed geographically to maximize resource efficiency, minimize the disruption to customers, and deliver benefits across a broad customer footprint or area.

The MYRP projects will result in significant customer benefits.

First, reliability. Fewer and shorter outages. Our self-optimizing grid, targeted underground, and distribution automation program focus in this area.

Resiliency. We must protect the grid against physical and cyber attacks, as well as severe weather impacts and our hardening and resiliency efforts are focused here.

Access to renewables and distributed energy resources. Our capacity and voltage regulation management work streams are focused in the area.

Multiyear rate plan projects and grid capabilities they bring are foundational and will support future technologies. With enhanced automation and control and situational awareness, we will operate the grid more efficiently and support new customer programs and offerings, giving customers more control and affordability options.

Equitable access to benefits. Our MYRP projects are spread across our geographic retail customer classes.

In this strategy, we'll serve customers into the future. As said above, these projects are foundational. The programs in our MYRP projects truly make the grid more flexible and adaptable. Our capacity and other work that enables two-way power flow for distributed energy resources is an example.

Automation and control technologies generate and capture huge amounts of data that we have not had before. This is extremely helpful for our grid operators, but also for our planning engineers, as they analyze and model our grid for future improvements and capabilities, using ISoP toolsets, such as MORECAST and advanced distribution planning.

And lastly, grid technologies will continue to advance and be integrated into new solutions to address changing customer needs.

There are four critical grid capabilities that mitigate the impacts of the mega trends and thus deliver customer benefits. The first of these is reliability.

The distribution grid of the past was built to serve customers' load. In that case, an outage for commercial industrial customers meant a loss of revenue or inability to operate their business. And for residential customers, an inconvenience, possibly minor or major.

As we move now to more of the hybrid environment, there is also impacts on individuals being able to work from home or remote learning for school kids.

The distribution grid of the future must not only serve the load, but also will be connecting distributed energy resources or generation to the grid. In that case, an outage not only has the historical context I just described, but it's also a loss of generation. When you layer in electric vehicles, there is now an impact to transportation as well.

We also must strengthen the grid and resiliency; being able to take a punch and recover quickly is critical.

The second is capacity. We need to

increase line and substation capacity, and enable two-way power flow for distributed energy resources and supports for vehicle electrification, both personal and fleet.

Automation and communication. Resiliency. The poster child for that in distribution is self-optimizing grid. It automatically detects faults, reroutes power, and minimizes the impact of those events on our customers. And also, official management of distributed energy resources, both solar and storage.

And lastly is voltage regulation. The quantity of distributed energy resources and the associated intermittency requires more precise voltage control across the distribution grid. An increased resiliency by blunting the impacts of those intermittently as well.

There is a lot of information packed in those four critical grid capabilities that I just described, and what I would point to is think of, as a child, the car you rode in, maybe your parents or grandparents, and the technology that vehicle had versus the vehicle you likely drove here today or maybe is home in your garage. It is night and day in technology and capabilities, and that's the transformation I'm describing for the distribution grid.

There are four main categories of our distribution grid improvements: substation and line; integrated volt-VAR control, or IVVC; voltage regulation and management; next, retail and system capacity; and last, hazard tree removal.

From the bar graph on the left, you'll see how the costs are spread, for a total of approximately $2.35 billion across the MYRP period.

We'll talk in more detail about the programs on subsequent slides, but first I want to explain why you see integrated volt-VAR control and voltage regulation and management outside of the substation line category, and also capacity and hazard tree removal both inside substation and line and also a separate category.

For hazard tree removal and capacity, this is the same work both inside substation and line as well as in the standalone category. For hazard tree removal specifically, at the bottom of the page, this is traditional identification and execution of this work, but it's aligned with normal cycle trending. Within substation and line, this hazard tree work is aligned and grouped with a significant amount of other work and is all executed together with an eye on resource efficiency and maximizing the customer benefits across the geographic area.

Capacity is very similar. It is the same work in both cases. At the bottom, it is traditional -- or standalone. It's traditional loads as well as distributed energy resources and electric vehicles. It is just not geographically located with a significant amount of other work. And within the substation and line category, it is aligned with a significant amount of work, again with an eye on resource efficiency and maximizing customer benefits across the geographic area.

I now want to talk briefly about integrated volt-VAR control, or IVVC, and voltage regulation and management. There is a current project, integrated volt-VAR control in DEC North Carolina outside of MYRP. It is going on now. That's addressing about 1,400 circuits in DEC North Carolina. It is currently being executed as a standalone project. It's focused as standalone due to regulatory commitments, as well as intense coordination for transmission work that has to go on inside the substation.

Specifically in this example, or this page, underneath the multiyear rate plan we've identified another 300 circuits in DEC North Carolina that we can provide that same core functionality of integrated volt-VAR control, and then implement conservation voltage reduction, as well as evaluate those circuits for DER penetration for voltage regulation and management assets.

How we plan in sequence our substation and line projects, I'll show here and speak through this. The two groups that are key to this effort are asset management as well as project development. An ISoP toolset, such as advanced distribution planning and MORECAST are used in these analyses.

I'll start in the lower left of this diagram and work my way around clockwise. We analyze each circuit, again leveraging the MORECAST data which is a 10-year hourly forecast by circuit, looking at both projected loads, including electric vehicle penetration, as well as distributed resources. We always evaluate, besides capacity, for the other critical grid capabilities such as reliability, automation and control, as well as voltage regulation and management. We then determine the potential programs to address any needs or gaps for those circuits and the associated substations. We take those balanced circuit plans at the system level, iterate those against any constraints, such as labor, material, or annual budgets, et cetera, and then we sequence that work at the individual substations. And lastly, those substation projects are aggregated to the area level for the MYRP projects for distribution.

I introduced our project-based approach earlier, but I want to reiterate here. You see that in the gray box at the left of the page. They're planned for a set of geographically clustered substations. The select improvement areas are selected based on analysis for individual circuits and substations, and lastly, those are aggregated together at the geographic level to be executed as an MYRP project. Again, delivering maximum customer benefits, minimizing customer interruption as well, and resource efficiency.

The analogy I would use here is think of a house remodel. You could do it a couple of different ways. One way is to do a lot of small projects. It likely takes a long time. Future projects may cause some rework of former projects. It's likely less efficient. And disruption and inconvenience for your family goes on forever. And it's harder to really enjoy the impacts of those individual projects as they're executed. Or you can aggregate it all together as an overall project, identify all the things you need to change or upgrade, hire a general contractor or an architect and designer as well, potentially. You plan and schedule that as one large project, it minimizes any rework. It's still disruptive and convenient, potentially for your family, but it does have an end, and the appreciation and enjoyment -- well, you appreciate and enjoy your entire remodel and all those modern touches, conveniences, and capabilities when it's finished.

Each remodel is different. It may be for efficiency, modern convenience, or maybe you need to modify your home for aging in place to care for an elderly parent. Each of our substations and the analysis done there is different as well for those individual projects.

I want to walk through a sample project shown here. This is a substation and line project in our Triad area, or Triad zone. It's area 251, which is our Mt. Airy, Rural Hall, and Kernersville part of that territory. There are 18 geographically clustered substations. You see those listed down the left-hand side. The green column headers across the top include not only the subnames, but also the improvement programs.

Let's specifically look at Key Street in the middle. There are seven different programs identified based on the specific needs for the Key Street substation and its associated circuits.

I want to reiterate, the needs for these projects are really looking at a 3- to 5-year rise, which is a normal horizon that allows for flexibility for future capabilities, even though MORECAST can predict overloads out to 10 years for that.

One last comment I'll make on this slide, the maturity of our estimates and the economic uncertainties we face. The estimates that we prepared were as of mid to late September to finalize materials for this technical conference, and some of the estimates will be updated in the PBR filing docket.

Our cost-benefit analysis methodology. Overall, the benefit and cost-benefit analysis uses the same methodology as previous filings.

Their expected financial benefits. For a customer that is in the form of typically liability, leveraging the interruption cost estimating tool for DEO, as well as operational costs, such as avoided O&M. An example of that would be if we execute a targeted underground project, we no longer need to trim the trees in that section of line, and that's an avoided O&M cost for all customers.

We also do them at the program level, similar to self-optimizing grid in previous filings.

We then have our data inputs. The planning inputs. We aggregate resource and input requirements. These really link back to the planning process I described a couple of slides ago, including the substation and circuit characteristics and the grid capabilities. Also, historical project data. Labor and material cost and labor and hours durations as well.

We then have our CBA inputs, which are the expected reliability improvements. We look at the historical performance of those circuits, as well as the historical improvements we've seen by executing the proposed program work.

We then calculate the program cost from historical data, labor and material cost, et cetera, with appropriate escalations. We also calculate the benefits for the customers, again use -- for reliability using the interruption cost estimator calculator as a data input.

We also look at operational benefit, such as avoided OEM, as I described a moment ago. And also other benefits as well. Fuel, specifically for integrated volt-VAR control, is one of the benefits. And we leverage project schedules for the timing of the cost incurred, as well as the benefits realized.

We then tabulate the schedule of cost and benefits in Excel. The benefits include outage avoidance, both sustained and momentary, as well as operational savings. The cost of capital, including contingency, and also O&M, both the implementation O&M for the project, as well as any ongoing O&M.

The present value is calculated for both cost and benefits. These are then netted against each other, and the benefit-cost ratio is calculated. We've also included sensitivity analysis to look at key values and how those impact the cost-benefit analysis.

So now I want to talk about the actual programs, and the next -- the remaining slides that I have are overviews of the program. There is two slides for each one. The first is an overview, the second is a benefit slide. On the right-hand side of the overview slide, as you see here, it has construction timelines, estimated in-service dates, projected cost, and grid capabilities enabled, and lastly House Bill 951 policy considerations that are addressed. I won't spend much time talking about those. Those are in the program summaries. I'll focus my comments, really, on the description and overview of the different types of work. And on the benefit slides, I'll highlight the benefits associated with those as well.

So integrated volt-VAR control. We also had that listed earlier with voltage regulation and management. And those are closely related, but they are separate programs. I want to go about them separately, but I'll also describe how they are closely linked.

So integrated volt-VAR control. This provides foundational capability by flattening the voltage profile on a circuit, and then we're able to operate in conservation voltage reduction. Let me explain what that is.

So we have a bandwidth of voltage that we operate in, high voltage and low voltage. When a circuit leaves a substation, it starts near the upper end of that voltage limit, and as we go out along the circuit, the voltage naturally degrades. When it gets toward the lower limit, we would install voltage regulators, raise that back up, and then again, as we go toward the end of the circuit, it would continue to degrade. But we maintain always within that upper and lower limit.

With integrated volt-VAR control, we

flatten that voltage profile from the beginning of the circuit at the substation all the way to the end. Once we flatten it, we can lower that voltage down toward the lower limit -- not to the lower limit, but towards it -- and that saves generation, and that's a huge cost savings of fuel for customers, a direct passthrough to customers. So that is conservation voltage reduction. Flattening the voltage profile, and then lowering that toward the lower limits to operate there.

Voltage regulation and management is there to mitigate the impacts of intermittency. So once we have that voltage toward the lower limit, we've got to make sure we could damp out any impacts from distributed energy resources. So that's why these two programs are looked at very closely together, and they're closely related in how we control voltage.

To focus back on IVVC, I describe the project that is ongoing now, outside of MYRP, but within the MYRP, again, we've identified another 300 circuits for DEC North Carolina that we can apply that voltage flattening and lower the voltage to save customers fuel in that case.

This work provides foundational control of distribution equipment to optimize voltage and power factors; regulators and capacitors, both inside the substation as well as out on the lines are deployed; new capacitors and regulators are installed if needed; we upgrade the controls for existing insulations as well; and we bring communications back to the control centers, and that's how we integrate that into the distribution management system to, again, operate the system in that more efficient manner that I just described.

You can think of that conservation voltage reduction as almost like the eco button in your vehicle, if you have that capability. They call it different things in different vehicles. But you could plan a trip, set your cruise control, press the eco button, and your car will automatically operate in the most efficient manner possible as you make your trip. That's what we're doing with the distribution management system for the grid.

The benefits of integrated volt-VAR control. I talked about this a little bit, but fuel savings. Reduced energy consumption saves fuel, and that's a direct passthrough to customers. Less generation reduces carbon emissions, it helps maintain proper voltage levels, and it also can provide foundational mitigation for solar intermittency and very light penetrations of DERs. And you see the benefit-cost ratio there in the lower right, 1.6.

Now, to the closely related voltage management program. So as I described a moment ago, this part of our effort is about damping out the voltage fluctuations from the intermittency of DERs, once we've applied that.

The planning engineers leveraged the signed toolset to perform the voltage and power analysis on each circuit. They first do the integrated volt-VAR control analysis to make sure we've got that capability. They will then immediately do a sequential study to look at any potential voltage regulation and management equipment that may be needed, based on the penetration expected on DERs.

There's really three levels of voltage regulation management equipment that will be deployed if needed. Voltage regulators and upgraded controls will be first. We may add capacitors to provide reactive power support if needed. And lastly, for circuits that have the high penetration of distributed energy resources, power electronics can be deployed to provide both voltage and reactive power support in areas. So, again, a particularly high DER penetration.

Regulators and capacitors are not new, but the quantity and upgraded control for two-way power flow are new. And power electronics are a new technology and provide instantaneous voltage and regulation or reactive power support.

You can think of voltage regulators and capacitors as really more of the course adjustments, when we need to make those adjustments on the circuit, and the power electronics as being a fine in instantaneous adjustment as needed as well. And those power electronics can also help keep the regulators and capacitors from making -- from trying to chase and make rapid changes, and allow them only to operate when they're needed for large changes on the grid, where the power electronics can take care of the more instantaneous needs. Voltage regulation is one of the four critical grid capabilities, and this work specifically addresses that.

So the benefits of voltage regulation and management. Improve voltage experience. It will maintain proper voltage level and reduce or mitigate power quality issues from increased DER penetrations. It supports the increased levels of DER connected to the distribution grid as they grow. It also supports customers' transitions as they choose rooftop solar and electric vehicles. And it helps prepare the grid for lower-carbon future by enabling two-way power flow, which is critical for increasing DERs.

Capacity. Capacity upgrades are needed to support load growth from both traditional loads as well as electric vehicles, and integration of distributed energy resources. Overloads are identified by leveraging the MORECAST data, which is an hourly load forecast over 10 years at the individual circuit level, and includes electric vehicle and DER projections.

Also, the ADP tool setters, advanced distribution planning toolset, includes automated solutioning, which allows us to analyze, at a system level, on how best to alleviate identified thermal overloads and evaluate potential solutions, including balancing, load transfers, conductor and device upgrades, and nontraditional solutions.

Capacity is really two categories, retail and then system. Retail, this is really the upgrades to our retail, our transition to distribution substations. We use the word "retail" to describe these stations, since they are the substations that serve our retail customers, as opposed to wholesale customers served by transmission. This work includes transformers, both upgrades and new transformers; breaker additions; and new substations.

System capacity. This is really the upgrades to our distribution lines or circuits, so really between those substations and the end customer, and this includes upgraded wires and equipment, as well as new circuits. And again, capacity is one of the four critical grid capabilities, and this work is specifically aligned to that.

The benefits of capacity. Improve reliability and resiliency, it reduces potential outages due to overloaded equipment or conductors, it mitigates outage risks associated in high-demand periods, and capacity improvements can also be leveraged by self-healing technologies. And capacity enables two-way power flow, thus supporting additional renewables and beneficial electrification.

Self-optimizing grid. This is an existing cornerstone program for distribution and addresses multiple critical grid capabilities. You may have also heard the term "smart-thinking grid." This is like a GPS in your car for the distribution grid. In your GPS or navigation app, you pick a destination, it picks a route for you, and as you're driving that route, if there's congestion or other problems on your route, it will automatically reroute you to avoid that. Our distribution management system and the automation software does the same thing on the distribution grid if it detects problems.

And for this work, the ISoP toolset, such as advanced distribution planning, as well as SOG automation are used by our planning engineers.

There's three major components for

self-optimizing grid. The first is capacity. This is similar work to our system-reliant capacity that I described a moment ago, but the additional capacity for self-optimizing grid is to provide an automatic backup for an adjacent circuit. It's not just to serve the native load.

So the capacity I described a moment ago was about supporting the native load on the circuit, including EVs and DERs. This is about being able to provide an automatic backup, where if there's a problem on one circuit, an adjacent circuit can pick that load up and serve those customers.

Connectivity is the second part. To be able to back each other up, these circuits have to physically be tied, and the ties between them have to be strong enough to support the load transfer from one circuit to another.

And lastly, automation. The intelligent switches and control software that turn the distribution grid into switchable segments and allows us to minimize the number of customers infected when we have a problem.

I want to describe the diagram in the

lower center of this page. It may be a little hard to see in the slide, but there is a larger view in the program summary. What this is showing, this is actually a self-optimizing grid network in our Greensboro area. It is just southeast of the Piedmont Triad Airport.

And what you see on the diagram, you'll see several small squares; some are red, some are green, and some have a pink color, which actually is red cross tags. Those squares represent the intelligent switches I just described. So those are the switches along those circuits as described. And the diagram here shows a cloud and a lightening bolt there on the left-hand side. That's indicating a fault for that area. And the two green boxes on either side of that lightning bolt indicate that there is no power flowing through there. Those switches have isolated that fault, or that problem on the grid, and all those switches have appropriately closed to reroute power around that problem area that has been identified.

And in this particular case, what this picture represents is after all that automated switching has happened, in that area where the lighting bolt is between the two switches, there are 433 customers that are out of power. Before we deployed the self-optimizing grid technology and the additional intelligent switches on the circuit, that exact same fault event would have had 1,525 customers out of power. So 433 are out as opposed to 1,525.

So maybe an analogy that helps describe what I'm talking about with self-optimizing grid and the interconnectivity. So if you think about a bicycle wheel, you've got the center hub and the spokes that radiate out to the rim. You then think about a spiderweb. A spiderweb also has a center, it has the radial spokes that go out to the door frame, or wherever the spider has built that web, but there is also tens, if not hundreds of connections individually between those spokes all around that spiderweb. That's the type of interconnectivity that I'm talking about with self-optimizing grid. Multiple pathways to reroute power, and also supports distributed energy resources. Multiple pathways to move distributed energy to where it's needed and can be used.

I mentioned earlier that self-optimizing grid addresses multiple grid capabilities. Three of the four are addressed by this program alone, and that's reliability, capacity, as well as automation and control.

The benefits of self-optimizing grid. I've described that in some manner, but I'll highlight it here. It reduces the number of customers impacted by faults and outages, and it reduces the number of outages and decreases the duration of those outages as well. And if you think back to the diagram on the previous page, between those two open switches, the green boxes, we can focus our crews immediately to where that problem area is, as opposed to having to patrol the circuits.

With the self-optimizing grid work we are proposing as part of the MYRP, for the DEC customers in North Carolina, that will provide an additional annual benefit of avoiding another 127,000 customer interruptions or outages, and an additional 26 million minutes of interruption to be avoided as well, and that does not include major-event days.

Speaking of major-event days, we had one of those recently here with Hurricane Ian. In Duke Energy Carolinas, this territory, we -- and we were less impacted than our DEP territory here in the Raleigh area, but in DEC, we saved 11,400 customer interruptions in that one event, and that saved 11.9 million customer minutes of interruption. That's approximately 200,000 hours of interruption that was avoided.

Our DEP territory was much greater impacted and saved 91,000 outages and 39.2 million minutes of interruption for DEP. That's about 650,000 hours of interruption saved.

That one event, for DEC, is approximately 40 percent of that annual incremental benefit that I just described. So the impacts and the operation is significant when we do have a major-event day, even though we don't include that in our projections.

It also expands solar and renewables. As I described with that spiderweb analogy, interconnected circuits enable greater two-way power flow and support the addition of renewables as well as beneficial electrification. And the benefit-cost ration you see there of 5.7.

Hardening and resiliency is the next area that I will focus on. Hardening and resiliency work is not new. It can cover a broad range of improvements and upgrades. It is designed to make the grid more resistant to outages, and when they do occur, to enable faster recovery and restoration.

I will talk about three different types of hardening and resiliency. The first is laterals. These are the tap lines off of our main circuits. I will then talk about vehicle accidents or public interferences, and lastly, storm.

And so an analogy to think about the backbone of our circuit versus the laterals, if you think about the backbone for distribution, think of that as a multilane suburban or urban highway or boulevard, and the laterals or tap lines are those side streets that will pull off of those main roads.

The process for this is data driven. We look at outage history and specific cost codes, as well as the physical condition of the conductor looking for damage or multiple splices.

The most common thing we find in this

program is an older vintage high-strength steel core wire that presents a corrosion risk over time. And we upgrade that to a high-strength all-aluminum alloy to avoid that corrosion risk in the future.

The benefits of the lateral program and hardening and resiliency, it eliminates the risk of outages due to conductor failures. Modern conductor and design or construction standards increase the grid strength to avoid outages. We're upgrading historically outage-prone assets, and that lessens the quantity and duration of outages during extreme weather and major events, and that helps bend the cost curve down -- the restoration cost curve down overall. And a reliable, resilient, lateral support additional DER and EV adoption in those areas, and the benefit-cost ratio is 2.5.

The next area is public interference, and specifically we're focused on car versus pole types of access. For those of you who live in more urban areas, such as Raleigh or Charlotte or Greensboro, likely, during the week on the traffic report in the morning, maybe once or multiple times during the week, there will be a traffic reporter with a live shot where a vehicle has impacted utility facilities. That's the type of events that we're looking to avoid here.

This is a data-driven approach, again, looking at outage history, but focused on specific car versus pole cost codes for the outages. We are focused on three-phase only, where the greater impacts would be, and it's also based on the frequency of events that we see in those areas.

The solutions for these would be a design change, including relocation, possibly undergrounding to remove the facilities or move them out of the impact zone for previous accidents.

The benefits for hardening and resiliency public interference. It reduces the risk of outages due to vehicle accidents. We're upgrading historically public interference prone -- outage prone assets, and that lessens the quantity and duration of outages. A reliable and resilient grid, again, supports distributed energy resource and EV adoption and growth, and the benefit-cost ratio here is 1.2.

Next is hardening and resiliency storm. This is also data-driven, looking at outage history, but looking at specific storm cost codes, as well as coupling that with a geographic analysis, looking at our coastal areas that are more impacted and exposed to coastal -- or, sorry, tropical types of events, and also our mountain zones that are more impacted and more exposed to winter-type events with heavy snow and ice.

There is a lot of information on this page about grade B construction and NESC loading, but, essentially, this results in larger and stronger poles, shorter spans of wire between those poles, and additional guy wires to withstand high wind and heavier ice loading in those more exposed areas in the coastal and mountain zone areas.

The benefits for hardening and resiliency storm. It reduces the risk of outages due to severe whether. Our more robust design and construction standards increase the grid strength to avoid outages, and upgrading historically outage-prone assets lessens the quantity and duration of outages during extreme weather events. And, again, that helps bend the restoration cost curve down for all customers. A reliable resilient grid also supports growth in EV and DER adoption, and the benefit cost ratio here is 4.0.

Distribution automation. This modernizes the protective device on the laterals or tap lines. Again, think of those side streets. This is accomplished by replacing traditional single-use fuses with intelligent electronic devices.

Most of our fault from an overhead are temporary. That would be such as a tree limb falling onto a line before falling onto the ground, or a wildlife contact. And traditional fuses are single-operation devices, and many times temporary faults become sustained outages and the fuse must be replaced to restore power.

An analogy I would give you here is think about the old fuse box. Again, think about your grandparents' house. If power went out in a certain room in their home, somebody had to go to the back porch, open the fuse box, look for the blown fuse, which was like a screw-in glass fuse, replace that fuse, and if the fault was temporary, then the power would be restored for that room wherever it went out.

Now think about the modern breaker

panels that we have in our homes today. If you had that same type of event where you lose power in a particular room, somebody has to go to the garage or the basement, where that breaker panel is located, find the tripped breaker, turn it off, turn it back on, and if the fault is truly temporary, then again, power is restored.

These devices are even more sophisticated than that. If they see a temporary fault, they will open, and then on the prescribed timeframe, they will close back in automatically. And if the fault was truly temporary, power is restored, and the customers only saw a momentary blink, as opposed to a sustained outage. And reliability is one of our four critical grid capabilities, and this work specifically addresses that.

The benefits. Improve reliability and resiliency, that reduces customer interruptions, both momentary and sustained, and the tap lines, themselves, become more fault tolerant. And the benefit-cost rate here is 2.7.

Long duration interruptions. This is an existing program. It relocates segments of overhead circuit backbone from hard-to-access areas to more truck-accessible locations. The target attributes that we have for this program is looking at radial distribution lines that serve large groups of customers or entire small communities. They are typically -- those lines are routed through inaccessible areas. Think off-road, swamps, mountain gorges, or other extreme terrain. They have consistently higher-than-average outage durations. Not necessarily frequency, but the outage durations are high. And the terrain changes that I just described are exacerbated further during extreme weather, such as a tropical event or a winter storm.

And the solution for these is to relocate those lines adjacent to a road right-of-way where they are accessible with their modern bucket trucks.

This reduces the risk of outages due to -- due from outage-prone line segments by making them more accessible. That accessibility reduces the outage durations. Upgrading our historically prone assets lessens the quantity and duration of outages during extreme weather. And, again, that helps bend the restoration cost curve down overall. And many times, in these areas where the lines are located now, we have to have specialized equipment, such as track vehicles, like a bulldozer or tank-type vehicle to access those equipment, and typically takes higher line tech resources as well. And a reliable resilient grid supports DER and EV adoption, and you see the benefit-cost ratio for this work of 16.3.

Next, targeted undergrounding. This is an existing program, it's data driven, and it strategically identifies and undergrounds the most outage-prone overhead line segments on our system. It reduces the outages for customers served by those line segments, but it also eliminates vegetation management costs for those converted segments, and that's a savings for all customers.

The attributes we're looking for in this program, unusually high outage frequency. Not duration, but frequency is what we're looking at here. The location of these lines typically is rear lots, so behind homes, and typically heavily vegetated. And the solution is to convert those to underground and relocate those to the front lot or adjacent to the road right-of-way.

The benefits of targeted underground. Eliminates the risk of outages due to overhead cost -- causes. The accessibility that we have by being front lot reduces outage durations. And upgrading historically outage-prone assets lessens the quantity and duration of outages during extreme whether across the system. And again, that helps bend the restoration cost curve down.

It also eliminates vegetation management cost. For all line segments that are converted with this work, that's vegetation line miles that are no longer needing to be tripped. That's a savings for all customers. And lastly, a reliable resilient grid supports growth in DERs and EV adoption. And the benefit-cost ratio for this work is 3.1.

Next is hazard tree removal. This is an existing program within our integrated vegetation management program. This work specifically identifies dead, dying, structurally unsound, diseased, leaning, or otherwise defective trees that are outside of our maintained rights-of-way. This maintains or improves reliability caused by trees that are falling from outside the right-of-way into our facilities. Our right-of-way maintenance program addresses the vegetation issues inside that actual right-of-way.

For DEC North Carolina, for the last five years, 2017 through 2021, the percent of vegetation outages caused from trees falling from outside the right-of-way range from 41 percent at a low to 58 percent across those five years. And I had one of the reliability engineers pull the data through Q3-4 for DEC North Carolina for this year, and we are at 52 percent of our outages this year are coming from outside the right-of-way through the first quarter. That's trees falling from outside the right-of-way.

The process is the inspection is done by qualified Duke Energy representatives using industry best management practices. If that inspector identifies extreme risk to our infrastructure and the failure is imminent, they will assign that to a vegetation supplier for immediate mitigation. All the other hazard trees that are identified are assigned to a vegetation supplier. They make contact with the owners, explain the work, and get consent to perform that work, and then the trees are cut down. In unmaintained areas, mitigation may proceed after a good-faith effort to contact the owner has been unsuccessful.

So the benefits for hazard tree removal, it reduces the risk of outages due to trees falling from outside the right-of-way. And it's a prudent utility practice. And one other thing I will point out is that, if you think about a vegetation outage from inside the right-of-way, that typically is a limb falling out of an existing tree. It may contact our lines and cause an outage, but typically doesn't break a wire, and rarely does it break a pole. When you have a 120-foot tall poplar fall from outside the right-of-way, the entire tree falls through the right-of-way, at a minimum it's breaking wire, and likely it's breaking one or more poles. So significant structural damage from one vegetation event occurs when we have a tree fall from outside the right-of-way.

Last is infrastructure integrity. The historical infrastructure integrity norms are changing to consider the dependency of distribution customer reliability on two-way power flow, and distributed generation as well.

Think back to my earlier comments on how outage impacts historically versus now forward. The programs that were historically in place to address past risk factors now are evolving to support more devices on the system, as well as changes in device operation due to power variability, and newer technologies that deliver new capabilities and challenges for the grid.

In this case, planned upgrades or improvements or replacements minimize the customer impacts, as opposed to a potential unplanned outage that actually becomes a planned replacement.

Examples here would be inspection-based asset replacements. That may be oil-filled equipment or poles. Oil mitigation. Changing to solid dielectric or replacing aged oil-filled transformers. Also greenhouse gas mitigation, moving from SF6 insulated equipment to solid dielectric equipment. It also included technological obsolescence. Think control panel replacements. That may be a functional obsolescence of the control panel or potentially it's unsupported by the vendor now and may have a cyber security issue.

And lastly, communication and automation. In many cases, we have legacy devices that we can now replace with SCADA-enabled devices where we could get visibility and control back in our control centers for our operators.

The benefits of infrastructure integrity. It reduces the risk of outages due to unplanned replacements or failures, and sustained infrastructure integrity enables more efficient restoration.

And earlier I talked about a house remodel analogy, and I was really focused -- or my example was focused on the living space of the house. But to do a renovation like that, you'd also make sure that the foundation was in proper order and didn't need work as well, and this infrastructure integrity work can be associated in that manner.

That concludes the distribution section. Unless there is questions from the Commissioners, I will turn it over to Dan Maley for transmission.

COMMISSIONER DUFFLEY: Okay. Thank you.

Let's check in with the Commissioners at this time to see if there are any questions.

CHAIR MITCHELL: Just one or two quick questions. Beginning with this last program you discussed, the infrastructure integrity, can you talk to me some about how you-all are identifying the infrastructure that you can -- or the equipment that can be replaced?

MR. GUYTON: Yeah. So some of it may be inspection based. We do pole inspections. We also inspect oil-filled equipment. So some of that may be generated from those inspections. Also, if we have a -- the control panel example I would give you, we have a legacy control, it may be functioning fine, but the vendor is sunsetting that control, is not providing any security updates to the firmware or software, we would identify that as something that needs to be mitigated as well when we're doing one of our projects in that area. So that's a couple of examples.

CHAIR MITCHELL: Okay. And then the other -- the other program I wanted to ask you about is the voltage reduction. Let me flip to my page really quick. So just -- this is really just more for my own understanding. You talked some -- I'm looking at page 17 where you discussed voltage regulation, and that's after the IVVC discussion, but you indicated that regulators and capacitors aren't new technologist. Y'all have utilized these technologies on the systems for some time now. But help me understand how you're using them differently now, or what the companies are doing to do to change the way you're operating these pieces of technology.

MR. GUYTON: So there's really -- there are really two pieces, and I'll try two explanations here. One is the traditional controls that are on those traditional capacitors and regulators were built for one-way power flow. They don't know how to behave when we got power flowing back in the other direction. So the control upgrades -- the equipment may be operating fine, it may be in the right location to deal with those issues, but we have to have an upgraded control. So that's one piece of it.

The second part is that, as we have the traditional application of regulators and capacitors, we're ready to deal with that natural voltage degradation as you go along the circuit, just as the load -- the further out you go, the more load you've got on the circuit. And that's worked fine. We don't have issues with that. But what we're trying to deal with voltage regulation and management, as we put more and more distributed energy resources, as cloud cover passes over a solar array, the production will drop from near maximum to near zero, and that causes a voltage fluctuation on the circuit.

So what we study is, is there additional voltage regulation equipment needed just to damp out that variability in voltage? And if it's really intense from a high penetration, that's where we could deploy the power electronics, which are a new technology, and that could provide instantaneous voltage and reactive power support faster than a traditional regulator capacitor can operate.

CHAIR MITCHELL: Okay. That makes sense. Thank you for that additional. I think you explained that the first time through, but I got it the second time.

All right. Last question for you. A

number of these -- at least my recollection is a number of these actions the Company has already undertaken or planned to undertake as part of this grid improvement practices.

So what -- to the extent there is anything, what is different about what you-all are proposing as part of this rate case, from the work that you've already begun under the grid improvement program?

MR. GUYTON: So much of this is a continuation of the grid improvement program. And that was -- or the reasons we were doing it was to address the mega trends, and the mega trends are still here. So that needs to continue in whatever, you know, type of recovery mechanism we're in. That work needs to continue.

So in some cases it is the same, to continue to address the mega trends. But the newer things that you'll see are the voltage regulation and management. As we see more and more DER and penetration come, we really have to be able to deal with that as those grow. And that's something that we really weren't focused on in grid improvement in the past from that effort. That's a new and emerging challenge that we've got in that space, as an example.

CHAIR MITCHELL: Okay. Just a follow-up with you there, the clustering -- the geographic clustering that you-all have talked about, I think the first time I heard the concept mentioned was the DEP technical conference, and now you've talked about it here too.

Is that a new technique that you-all are employing, or have you -- had you already begun?

MR. GUYTON: We've done that to an extent, but we're really looking to maximize that. What we recognize is, with the amount of work that we need to do, and the pace at which the changes are coming, that's a way for us to really maximize resource efficiency. We had some resource constraints early in grid improvement post COVID. We worked through those now. But that has taught us that we need to make sure we maximize the -- our historical approach has been more programatic.

So we identify a particular type of issue we're having on the system and attack it more programatically. What we found is we can bring benefits holistically to customers by identifying -- kind of like my analogy of the house remodel. Identify everything in an area, let's package all that together and go execute it at once. We're not mobbing and demobbing resources. The impact to customers has an end. We move into the area, we do all the work necessary, and then we're out of there, from that perspective as well. And then once we leave again, the benefits are substantial for customers, as opposed to this program to solve this problem and then this program. We put all that together.

CHAIR MITCHELL: Okay. And then last question for you. How much of the work that you-all are doing, specifically on the distribution side, is informed or prioritized by the other types of needs you're seeing on the -- on the grid? For example, you know that there is a focus in a particular area or location for fleet electrification, just as an example. Is the work that you're undertaking on the distribution side, sort of, following that need, or are you-all deploying these -- this investment, sort of, irrespective of other dynamics on the grid?

MR. GUYTON: No. We're intending to

take all those dynamics into play. An example you gave of fleet -- or electrification, including fleeted, the MORECAST data that the planners actually use has a prediction not only for light-duty vehicles but also medium and heavy duty. So that's looking in that propensity that we may have fleet EV coming in that area. So all that is rolled in as the planners are looking at it as an example.

CHAIR MITCHELL: Okay.

MR. GUYTON: They intend to be holistic in that planning effort.

CHAIR MITCHELL: Okay. Who owns that MORECAST data? Which division within the company?

MR. GUYTON: So the MORECAST data, itself, is under the ISoP team.

CHAIR MITCHELL: Okay.

MR. GUYTON: But we leverage that data in planning, because we need that to be able to do our work and analysis as well.

CHAIR MITCHELL: Understood. Okay. Thank you.

COMMISSIONER DUFFLEY: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Yes. Thank you for this presentation on the distribution side. It's been informative. I just had a question about the small-optimizing -- I mean, the self-optimizing grid.

So it will reduce the number of outages, and that's one of the main features or benefits, but is there any reason to expect any -- or I think there would be some, but would there be much impact on storm recovery costs coming from that? And what I was thinking is, you had used the analogy -- I think this was -- of all the interconnects. So there would be storm damages still, but there would be less outages. Would -- any reason to -- is there any correlation between the storm recovery cost?

MR. GUYTON: I think there is, and not only for the self-optimizing grid, but also other work we're doing, when I describe the distribution automation on the laterals. In many times, in storms, especially, the faults are actually temporary, but if the devices, you know, see that as a permanent fault, there's an outage that we've got to send a crew to do that. The more automation we have that can make the system more fault tolerant and restore automatically, that's one less event we've got to send a crew to even analyze. And we also leverage our AMI system to actually ping meters to see if the meters actually have power or not, as opposed to rolling a truck. We can tell if there is power to a customer's home by pinging those meters during restoration. So that avoids a lot of truck rolls at the end of a major event for single outages.

COMMISSIONER BROWN-BLAND: I will say I was convinced during Ian that the hardening had paid off, because I did have momentary flickers, but we never went out, and that was some awesome wind.

MR. GUYTON: Excellent.

COMMISSIONER DUFFLEY: Commissioner McKissick?

COMMISSIONER McKISSICK: This is following up on a question that Chair Mitchell asked you. Since much of what we're seeing here is a part of what's in our grid improvement program, our other initiatives that had been undertaken, is it possible, as things move forward, you know, to really identify the significant changes between what was originally proposed and what's being proposed now, as well as compare/contrast the cost of what was originally projected to what the projected cost is today? Kind of, almost picking up on a comparative analysis where it was last left off to where you are moving forward with it, to help focus a little bit more on the changes that have occurred, either in terms of scope or cost.

MR. GUYTON: I'm not sure how to answer that. Let me attempt.

COMMISSIONER McKISSICK: Sure. I understand.

MR. GUYTON: So this work is much broader than grid improvement. So it includes some of the same type of work, but again, this is a different ratemaking mechanism for appropriate distribution work. So it's not limited to -- with our grid improvement work, it was very narrow and specific for what we were allowed to do in the grid improvement under that deferral, really looking only at modernization. And this is really holistic. This is all distribution work we need to maintain and advance the grid. So I don't know --

I mean, that's a verbal comparison, but not a dollars comparison, but that's what I see as the difference is, we still need to continue to do grid improvement type of work, but the MYRP is really a different ratemaking vehicle for all the distribution work we need to do, or much greater portion of it.

COMMISSIONER McKISSICK: And that I appreciate and understand. I'm just trying to put it more in context in terms of trying to see what was being worked on and focused on before, kind of looking at where that stands compared to what you're projecting now, and then understanding that there are different components that are obviously beyond what was originally contemplated. You know, how that, kind of, fits together as part of a multiyear plan.

MR. GUYTON: So let me try this.

COMMISSIONER McKISSICK: Sure.

MR. GUYTON: Within grid improvement, for DEC North Carolina, we had self-optimizing grid, the integrated volt-VAR control, distribution automation or fuse replacement, and I think hydraulic to electronic reclosers. Those are the ones I specifically remember. All of those are still imbedded within this. I mean, self-optimizing grid is still there as a standalone. Those hydraulic-to-electronic reclosers are included in infrastructure integrity. I talked about going from oil-filled equipment to solid dielectric. That's that -- that particular portion of it. And then distribution automation, or fuse replacement, that's the same thing again. So SOG and fuse replacement -- or, sorry, distribution automation, those are really the two same things that we had in that space. And IVVC, we've identified another 300 circuits within the MYRP period that we could do just like we were before. We'll continue -- we'll finish IVVC as it stands now for the 1,400. So does that help as well? Those are really the four pieces I remember. So this is much broader.

COMMISSIONER McKISSICK: And in terms of the initiatives which are being undertaken you just identified, in terms of costs that were anticipated originally versus the costs that are being proposed today, particularly in light of the inflationary environment that we're in, there must be change, or at least I'm assuming there likely is change in the costs that are being projected, which are identified pretty discretely here. I don't know how much the magnitude there has changed.

MR. GUYTON: Yeah. I couldn't quote a number in that space, but certainly from, you know, filings we did in 2019, you know, inflationary pressures, most recently, as well as just natural escalations are all imbedded. We've done our best to take that into account in our cost estimates, based on the latest information we had as we prepare for the technical conference for those, so that's included in that manner, but I couldn't give you comparison from previous cost to this.

COMMISSIONER McKISSICK: And when you update those costs, what type of indexes do you use? I mean, how do you go about --

MR. GUYTON: I know we work back with -- I don't know the details, but I do -- my understanding is we work back with supply chain for any indications, the latest information they have for what they're seeing in supply chain. I believe they work with treasury for the cost of capital and inflation pressures, but I don't know the nuances of how that goes. But that's -- that's been our normal method. We go back to those same groups within Duke to look at that information and provide those updates.

And as I stated earlier, as we go forward, there'll continue to be changes. I think the fed is meeting today to decide whether or not to raise interest rates again. As we go through the filing process, we'll update our estimates appropriately and keep the Commission informed, but I would certainly expect changes. We've done our best to incorporate that in what we presented, though, so far.

COMMISSIONER McKISSICK: I was just trying to get my arms around that. And the more, you know, you speak in addressing that, it's helpful. It's just that we're moving into this new paradigm where we are looking forward rather than looking backwards, and I don't know, in terms of if we were to look backwards, in terms of what has been done, based upon what was projected previously, and then look forward in terms of where we are moving over this next three-year period, it's gonna be somewhat more challenging.

MR. GUYTON: I agree.

COMMISSIONER McKISSICK: Particularly in this current environment. But thank you.

COMMISSIONER DUFFLEY: Commissioner Kemerait?

COMMISSIONER KEMERAIT: Thank you for the information and the presentation. I just have two questions. The first is a follow-up to Chair Mitchell's question about new technologies that you provided in the presentation, and I'm particularly interested in the technology for the two-way power flows, and can you describe -- or can you tell us, to the extent to which it has already been deployed on Duke's system, so I could have a better understanding of where we are in that process?

MR. GUYTON: Yes. So one example, and I think I mentioned this a moment ago, is controls on our voltage regulators. The traditional controls really only are effective for one-way power flow, which was perfect for the way we used to operate. But the controls we're replacing now -- and these are being deployed today. That is our new standard. They are out there. I couldn't give you a number of how many have been changed, but we are in the process of changing those now, as we IVVC before we get to the MYRP period. So those are being done today. So that's one example of how we've integrated two-way power flow.

And all of our standards for material and controls going forward incorporate modern advances, really what we need for the future as we upgrade the controls as well, but that's probably the quickest changing thing is really controls.

COMMISSIONER KEMERAIT: Okay. Thank you. And my last question is, the last two programs you talked about -- I think the hazardous tree removal and then the infrastructure integrity program, you didn't provide a cost-benefit ratio for those, and is there a reason that you did not provide it or cannot provide the ratio?

MR. GUYTON: Yeah. Great question. So for hazard tree and infrastructure integrity, the way we're able to provide a cost-benefit analysis is mainly for the reliability benefit to customers. And for things such as self-optimizing grid, we can very specifically identify this is the device that would have opened, now we've upgraded the technology, now this is what happened, and produce a cost estimate of here's the value that we save customers by not having that outage.

For hazard tree removal, the damage is so variable, and we don't know where they're gonna fall from, and how to predict that. So for those types of efforts, we really have to take a more multiyear view. We look at, like, maybe a five-year history. But to be able to point to it and say the hazard tree saved this much money, that's where it's hard to do a cost-benefit analyses.

However, as we see the percentage of outages from outside the right-of-way drop, we have less significant damage -- structural damage when they fall. That's the benefit. How to actually put a number on that and not double count that benefit somewhere else, that's extremely difficult.

We see that as an obligation to serve, specifically for hazard tree. We have a known risk out there that we know causes us problems. We can't predict exactly when or where, but if we can remove that risk, we feel that's our duty and a prudent utility practice.

And infrastructure integrity the same way. If we've got a crumbling foundation, you got to fix it. You may get different cost estimates for what you do to fix it, maybe look at different vendors or technologies, but you're not gonna not fix the foundation program. Kind of back to my house remodeling analogy. So that's the reason. Where we could put specific dollar and stand behind it, we do those cost-benefit analyses.

COMMISSIONER KEMERAIT: Thank you.

MR. GUYTON: You're welcome.

COMMISSIONER DUFFLEY: Commissioner Hughes?

COMMISSIONER HUGHES: I just had a quick follow-up on that, because you mentioned your ability to do the benefit-cost analysis.

Could you just comment a little bit about your comfort level with the ICE calculations? It just seems to be such a big -- big part of this planning effort, and from what I understand, it's been updated a little bit, but there is still -- just still potential concerns about that, and is Duke doing anything about that.

MR. GUYTON: Actually -- so I'll answer

the last question first. We are participating in future updates as a participant in that. I don't know exactly our particular role, but we do think it's the best thing out there. There's really nothing else comparable to do that. So it's our best attempt to put a dollar figure on what that is worth from our perspective.

One thing we've done uniquely in these filings, including the DEP tech conference before, is in previous filings, so back in 2019, there was a standard table of outage durations and values around those. Our team actually leveraged the online version and created unique value specifically for North Carolina, and what those surveys from the utilities brought back in that space. So that's one enhancement we've made in how to use it. And I would expect future editions of the ICE calculation, or wherever that progresses to, to have even more enhancements to be more specific, and they'll gather more data as we go, so it will only get better. But we do see that as an industry-accepted and best tool that we have to put a value on that.

COMMISSIONER HUGHES: Thank you. That

makes sense.

COMMISSIONER DUFFLEY: So it sounds like you don't have an answer to one of my questions. I was also gonna ask, I understand that the ICE calculator is currently being updated and that Duke is a participant in that update.

So can you expand, anyone on the panel, expand any further about your participation and what the timeline is for that ICE update?

MR. GUYTON: I can make one more comment about the timeline. I don't know the details about their participation. But my understanding from talking to some of our folks that are involved is, it's probably gonna be 2024 or '25 when the next version is published. I don't know how firm that information is, but that was from my conversation of some of the folks involved.

COMMISSIONER DUFFLEY: Okay. Thank you. And do all of the programs that were presented here today mirror the programs that were presented in the DEP technical conference?

MR. GUYTON: Yes, with one exception, and that's the integrated volt-VAR control piece. So that's the one thing that you'll see different here. And the reason for that is, if you may have been familiar with, in DEP, several years ago we implemented DSDR, distribution system demand response. That essentially was IVVC, the exact same thing, flattening the voltage profile from the substation all the way out, and it's just that the mode we were operating in was peak-shaving only. I'm sure you're aware, we're actually converting DEP now to still have that IVVC, but convert it to a dual mode, where it still maintains that peak-shaving capability for the cold winters and hot summer days, but also, outside of those, I'll call peak days, will operate at conservation voltage reduction and bring additional fuel savings to customers.

So really, just, the utilities are in two different places. DEP did that work many years ago, and DEC is now in progress to bring that foundational capability, but that's the only difference, besides, I guess, number of units or scope, but the programatic work is the same as before.

COMMISSIONER DUFFLEY: Okay. Thank you. And then with respect to the volt-VAR control, you mentioned that 300 circuits have been identified. I'm just trying to obtain the scale of this project. What percentage is 300 circuits with your total system?

MR. GUYTON: Ooh. That's a good question. I'll contrast it this way. The original IVVC project that's ongoing right now in DEC is 1,400 North Carolina circuits. So this is about another third on top of that for those. I don't know the total percentage of circuits in DEC North Carolina, specifically, but it's pretty substantial. That's a -- that's a great portion of the system under that control.

COMMISSIONER DUFFLEY: Okay. Thank you. And then with respect to your infrastructure integrity, you mentioned that -- you listed examples of this work, one of which is end-of-life work. Again, just trying to obtain a scale or scope.

What percentage of this proposed work can be categorized as end-of-life?

MR. GUYTON: I do not have that number in front of me from that perspective.

COMMISSIONER DUFFLEY: Okay. And then

last question is with respect to -- you started out the presentation regarding the IIJA, and do you anticipate receiving any funds during the pendency of the rate case?

MR. GUYTON: I do not know the exact timing of the awards for that, so I'm not sure, but certainly if we're in that process, we would keep the Commission informed of any updates in that space and how to appropriately incorporate that.

COMMISSIONER DUFFLEY: Okay. Thank you. Any other questions before we move on? Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: I had just flipped back to this before Commissioner Duffley asked that question.

With regard to the IIJA, on your slide you had the phases -- phase 1, 2 -- where is Duke at this current time in the process?

MR. GUYTON: So I don't know the alignment exactly to the phases. That was a pretty high-level slide. But specifically, the next thing we're expecting is the FOAs here in fourth quarter 2022. That would be the next piece. But I don't know the very detailed steps through our process, but we're continuing and we'll keep the Commission informed of any movement in that area.

COMMISSIONER BROWN-BLAND: Thank you.

MR. GUYTON: You're welcome.

COMMISSIONER DUFFLEY: Okay. I think you take a break. You have a small break, correct?

MR. GUYTON: Yes.

MR. MALEY: Ready to continue?

COMMISSIONER DUFFLEY: Yes.

MR. MALEY: All right. Thank you. Okay. My name is Dan Maley. I'll be speaking -- are we good to continue?

COMMISSIONER DUFFLEY: Let me check in with Linda. Do you want to -- or Joann, sorry. Good? Okay. Please go ahead.

MR. MALEY: All right. My name is Dan Maley. I'm the director of transmission compliance. I will be speaking to transmission projects today. I'm gonna start with an introduction of our transmission project areas. We'll drill down to discuss the benefits of these projects, and how we identify and evaluate each project to include in the multiyear rate plan. I will then preview the projects with some specific locations highlighted, so we can look at some examples where we're executing this work.

I will start off by just noting some differences in terminology between the discussion Mr. Guyton just had and the transmission projects, how they are arranged. You heard about projects and programs and geographical groupings. Transmission, we have seven total projects. We do have project locations under each -- under each of those areas, and we do perform a similar approach, where, when we have work in a similar area on a given circuit in a substation, we are bundling that work together to really maximize efficiency from both a design, execution, construction standpoint. But I will primarily talk about projects and project locations.

Just to introduce the four areas that I'll speak to today on the transmission side. You can see those along the left column. I'll get more into characteristics and benefits in the subsequent slides.

I will be speaking to system intelligence. This is really about improving grid awareness. Getting our grid operators more information, technology upgrades, and similar.

Hardening and resiliency. You heard some examples of this already, but this is about a stronger and more resilient grid. Preventing outages and also ensuring the transmission system can respond after outages do occur.

Transformer and breaker upgrades. This is a similar project scope where we are targeting end-of-life assets. We're proactively replacing those assets prior to failure, and we're improving, therefore avoiding reliability impacts to our customers down the road.

And then the last area, capacity and customer planning. This is really about meeting customer demand, new customer connections for specifically industrial customers is one example, coming on to the transmission system. Meeting our compliance obligations under NERC standards, and also our expansion of the transmission grid from a capacity standpoint, which includes our red zone expansion plan, which I know the Commission heard details about under the Carbon Plan filings.

I am gonna proceed on. On the next slide, what we can see here on the left-hand side is, sort of, a portfolio view of our transmission portfolio. On the bottom, you can see the capacity and customer planning project is the largest single by investment standpoint, and going up the line there, approximately a $1.75 billion total portfolio.

I have already done a high-level introduction of the various categories, and as mentioned, I will talk about more in detail. I do want to just reference a few of the exhibits that we filed.

The cost by the overall project for each of these categories, as well as by the specific location, is shown in our transmission project details exhibit. And the -- I will note that the project location details and costs are based on our plan as of late August, early September timeframe. So similar to the discussion by Mr. Guyton, in accordance with the normal project development process, those projects will continue to advance in maturity, and we may see some variance between what is in the included exhibits and what is included in our -- in our filing.

From a high-level standpoint, some notes that I did not mention already, hardening and resiliency, you will see, is actually broken down into three project scopes. Transmission line H&R, these are really our high-voltage transmission circuits, 44 kV all the way up to 500 kV on the DEC system. Substation H&R is about targeting assets within our transmission substations. These are really the key locations on the grid where we're transforming our voltage from a transmission level down to a distribution level to send out to our customers on the grid.

And then our transformer and breaker upgrades. I mentioned previously we're targeting end-of-life assets and upgrading those assets to enhance them with new technology and improve reliability.

Our capacity and customer planning. I mentioned some examples of that. At this point, one additional comment I'll make is, we are processing our capacity projects through the ISoP process, evaluating non-wires alternatives, looking for the most efficient way we could actually meet the capacity demands as we model the transmission grid. So there are several different ways we could approach a solution to meet a capacity constraint.

So let's go to our next slide. I'd like to talk about how we developed the portfolio that we have included for our transmission plan. Thank you, Brian. We take a systematic risk-informed approach. We're looking at the costs and, of course, benefits. So we are performing a traditional benefit-to-cost analysis.

From a high-level standpoint, we are starting with subject-matter experts in our system planning organization. They really model the transmission grid. They work very closely with distribution planners looking at retail growth and changes, and also our generation planners, looking at where do we have generation currently on the grid, where are we retiring generation, where do we have new generation coming on the grid.

And then the other group is our asset management experts, and this team is focused on health of our assets on the grid. End-of-life planning, technology improvement, and how can we sponsor projects to enhance the product that we're delivering to the customers.

So we're factoring multiple different

items, which you could see around the outer circle here, when internally prioritizing when to proceed with a specific project location. So we're looking at financial risk; safety; security; cyber security, of course; regulations -- compliance with regulations; environmental risks; grid capacity due to growth; and, of course, reliability and integrity.

For our multiyear rate plan, from a quantitative analysis standpoint for the benefit to cost, we really are focusing just on the reliability piece, and we are utilizing the ICE calculator in a similar manner, which I'll explain a little bit more here on the transmission side.

So we have the ICE calculator imbedded within a third-party software. The software is called Copperleaf. And what we're doing is we're actually evaluating, through a questionnaire, each project location that our sponsors have identified a need for. Those are our data inputs on the left side of this slide. Of course, cost-benefit is very important to get an accurate benefit-to-cost ratio. We are using historical project costs for like work in like locations. And that's informed by professional estimators.

Our asset condition. This is one of the key inputs that our experts rank and rate based on field -- field assessments performed. So actual inspections in the field, work order history prob- -- this is ultimately informing the probability of failure. So based on the condition, based on similar failures, what is the probability of failure we expect?

Risk of overload. This is a model we use for capacity projects. So what's the current load on the system? What is the load projection going forward? This is really based on our planning studies and specific for our capacity project. But again, it ultimately leads to what's the probability of failure.

And then the other part of the risk equation is consequence of failure. And the way we rank that, it's based on the various factors, including voltage level. So voltage level as a corollary for load, is this our 44 kV sub-transmission system or is it our 500 kV system? Is the load served by multiple sources, what we call "networked," or is it a radial load, which is one source? And then what is the customer mix? Are we serving industrial customers from this transmission line, commercial customers, or residential customers? And that factors in as well.

We're then processing that through, again, the ICE calculator you heard some discussion of already. We're looking at the annual avoided outage benefits. We're summing that up over a 30-year expected life. So that really starts with once we replace that asset, what are those reliability benefits that we achieve through avoidance of failure? So we are using failure curves to determine and inform this benefit-cost approach. We're using a net present value for the ratios, and then we also performed a sensitivity analysis. So after completion of the benefit-to-cost analysis, we presented this in our exhibits where we vary the cost, vary the benefits, and you can examine how that impacts the overall ratio.

All right. I'll now get into our project areas and explain a little bit about the more specific benefits associated with each project and look at some examples.

On the first slide you'll see in these series of seven projects, on the right side you'll see construction timelines, in-service dates, some of the details from our project summaries. I won't go into detail on that, but it is available for the Commission to see.

What does system intelligence mean? What is our system intelligence program? And quite simply, it's really our ability to obtain more useful information on the grid in order to give our grid operators and engineers better information to make informed decisions in the best interest of our customers, in the best interest of ensuring a stable and reliable grid.

Digital relays and remote operated sectionalizing switches. You see two pictures of those on the slide here. These are two of the scope areas. They really work in conjunction with each other.

Digital relays. Essentially, what we're doing is we're removing a legacy relay design, which is an electromechanical device, cams, levers, springs. We're replacing that with a computer.

And this computer is able to, of course, not only sense a fault -- ultimately what a relay does is sense a problem on the grid and sends a signal to a circuit breaker to open to isolate that problem. So these new relays, they perform that function, but they also provide specific information to the operators on where that problem occurred. And they do that through analyzing fault current and determining distance to faults. So what we're doing is, we're upgrading the information that the grid operators have so they can make intelligent decisions on how to reroute power, and they do that through circuit breakers and substations, and then remote operated sectionalizing switches that we deploy out on transmission lines.

The advantage of this is we can break up transmission lines that are 20, 30 miles long. Sometimes multiple different fingers or radials or taps emanating from them. We can break that into smaller segments. So after an outage, we get the information from the relays on where the outage occurred, the operators make the switching decision from the control center, and we're able to either restore partial or sometimes full customer load.

That's a significant improvement from the legacy model, where all we know is we have breakers that have opened at substation to isolate a problem that occurred on the transmission line. We dispatch linemen, they have to go find the problem, sometimes going down very difficult-to-access right-of-ways, through difficult -- mountainous terrains, swamp areas, and this leads to extended outage times. Once we do find the problem, we then need to go to a manual-operated sectionalizing switch, if there is one available, or just make the -- just make the repair and restore the outage.

So this combination of technology can take outages that have historically lasted several hours and turn them into several minutes. So it's a huge improvement for our customers.

The other area I'll mention for system intelligence, you can see in the center bullet, is our remote substation and asset monitoring. Remote substation monitoring is essentially traditional SCADA improvements, where we have the supervisory control and data acquisition. But the asset health monitoring is a new project for us -- relatively new project -- and what we're doing is deploying monitors we call condition-based monitors. These are primarily on our substation transformers, and these monitors go on the transformer and they analyze the oil and other characteristics in that power transformer to determine "do I see signs of a problem?" They get that -- we take that information, we process it, actually through a machine-learning platform called our health and risk management platform, and use that to make informed decisions about -- for near-term, do we need to switch this out of the service? Do we need to take this substation out of service before catastrophic failure? And then for longer-term, we inform our power transformer replacement program, which I'll speak to later on in the slides. So getting this asset-specific health information is a huge advantage for us for being able to be more proactive with our assets.

All right. Here we can see -- just to briefly introduce the format of these, the second slide of each project, on the top you'll see the benefits -- I was speaking to those through the examples -- and you'll see the benefit-to-cost ratio numbers.

I'd like to focus on the pictures in the box on the bottom, though. What we're seeing here is a specific project location, which is our Waco 44 kV remote operated sectionalizing switch.

So in the image on the bottom left, you can see the blue line is actually the 44 kV transmission line. I mentioned earlier a multi-tapped line or multiple fingers. You can see all the different branches of this line. It's about 24 miles total with those branches. And we actually serve four different customer substations, which you can see there in the images, and we also serve one solar plant that's actually currently in the -- in the planned interconnection phase. So this is a future solar location.

The advantage of deploying a remote multiway sectionalizing switch on this line is, if we do have a problem, again, our grid operators can sense that, they can reroute power, they can isolate the faulted portion in a much smaller segment than the entire circuit being operated from the substation right from the circuit breaker. So we can, kind of, isolate that problem to a smaller area, and the rest of the customers, as well as the generation resource, can be restored and be able to provide its benefit back onto the grid. So this project location, specifically, improves on reliability for about 6,000 customers directly served off this line.

The next project I'll speak to is our line H&R, or line hardening and resiliency project. Several different scopes of work under this project. I'll start out by explaining the pictures you can see on the bottom.

What you see on the left-hand side is our 44 kV transmission system. This is actually a broken pole. You can see that the top half of the pole is broken and sitting down on the ground here. This -- this system is somewhat unique. It was built out to support the textile manufacturing industry in the Duke Energy Carolinas territory. What we're doing is we're proactively upgrading this system and we're making improvements beyond just replacement like in kind.

So, specifically, for wood poles, we're replacing the wood poles with steel poles, which is significant reliability improvement, especially in extreme weather scenarios. So we are targeting the specific poles that are degraded. We do visual inspections, hammer testing, and other condition-based means to identify those poles, and then we plan them for future year replacement and upgrades with steel poles.

Those steel poles are, like I said, a significant improvement when it comes to extreme weather, high-wind scenarios. We don't have steel pole failures for the vast majority, whereas, in extreme weather scenarios -- again, hurricanes, wind storms -- we're seeing wood pole -- wood poles as a significant improvement opportunity.

The other -- in addition to individual locations on the 44 system, specific line segments that are particularly problematic from a historical outage perspective are targeted for rebuild. And we're actually rebuilding that 44 kV system to the 100 kV standard. So in addition to replacing the poles with steel poles, we are actually elevating that lineup. So you can get a little bit of sense of the height difference between these two pictures, but on the right is a rebuilt 44 kV system. So the 100 kV standard, higher poles, larger insulation, larger --

COMMISSIONER DUFFLEY: We have a quick question.

MR. MALEY: Sure.

COMMISSIONER DUFFLEY: Chair Mitchell?

CHAIR MITCHELL: I wanted to interrupt you at this moment so that you can give us a little bit of education.

Can you talk some -- I'm interested in the 44 kV system. How widespread is that system? How much 44 kV line do you-all have out there?

MR. MALEY: It's -- we have approximately 2,500 miles, so it's --

CHAIR MITCHELL: Can you put that in some context for me? I mean, how much -- do you have less of that than -- well, just talk about it relative to the 100 kV.

MR. MALEY: Sure. Sure. We have about 13,000 total miles of transmission line on the DEC system. About 2,500 of that is 44 kV system, about 7,000 is 100 kV system, and then the remaining 230 and 500. So hopefully that gives a little context.

CHAIR MITCHELL: And is the 40 -- I mean, will the system always require sub-100 transmission lines? I mean, do you anticipate that there will always be 44 out there?

MR. MALEY: The system will not necessarily always require it. So we do -- we are anticipating or enabling capacity upgrades to 100 as we rebuilt the system. So although we -- at this time, we don't have any discrete plan to eliminate 44 by any means, due to the widespread nature of it, through our rebuild program, what we are doing is allowing, as capacity needs dictate, we can then modify, essentially, the substation equipment at either end of the line and actually be able to energize it to high voltage level.

A lot of the 44 kV system, as I mentioned, serves manufacturing customers, industrial customers. So their equipment is designed to receive the 44 kV voltage, so we generally wouldn't obligate them to upgrade. If they were interested in upgrading, you know, that's -- that's kind of -- I would say significantly down the road. Not part of our current plan.

CHAIR MITCHELL: So those customers take directly off the 44 kV?

MR. MALEY: That's correct. Yes.

CHAIR MITCHELL: Okay. All right. Thank you. I appreciate you entertaining that question.

MR. MALEY: Yeah. You're welcome.

All right. So I was discussing our rebuilt program, and I think I've already hit a few points there -- right there that I was gonna make, but really we're enabling future capacity upgrades. This is reliability driven work, but with substation upgrades on either end, whether we have capacity needs for additional customers, whether it be, you know, retail, residential, or industrial, or generation demands for distributed energy, solar, et cetera. This is a great enabler of that.

The other project scope that I'll mention here is cathodic protection system. The 100 kV and 230 kV system, as well as our 500 system is a steel lattice tower construction. I'm sure you're familiar with seeing some of these large towers around the service territory. But what we're doing is we're installing anodes at these towers that serve to protect against corrosion degradation.

Where the towers actually imbed in the ground line, that is the most probable location of failure, right? That is where the corrosion actually starts. Typically, that's the weakest point of the tower. We're actually installing anodes at these locations. It arrests the corrosion. We restore that tower leg back to a like-new condition, and significantly life-extend the -- or, excuse me, life -- provide a life extension to that specific tower. So this is a really important program for us for those highest voltage lines where we do have a tower out on the system.

Again, this is a condition-based program. So we are taking lines where we know, from past inspections, we have identified high rates of corrosion due to the specific soil conditions or other factors, such as difficult-to-access lines, harder to access during outages, and we're targeting those lines for these enhancements and upgrades.

I'll speak to a specific project location. This is our Quebec 44 kV line. This is actually out in the Pisgah Natural Forest, and we are rebuilding approximately 6 and a half miles of deteriorated line structure. And this is a high -- a high-outage line. So not just in frequency, but what happens is, when we have an outage on this line, and vast majority of outages are trees falling from outside the right-of-way due to the forested nature of this -- of this circuit -- it's a very-difficult-to-access line, and we tend to have long outages.

Finding that problem and getting linemen there, getting vegetation management crews there to actually cut the tree off, we've had two outages longer than 12 hours on this circuit in the last five years. And again, both from trees outside the right-of-way.

This line serves almost 7,000 customers. So we're rebuilding this up to that 100 kV standard, we're elevating those poles higher up above many of the trees, and greatly improving the -- or reducing the chance of a tree actually falling from outside the right-of-way onto that line.

In addition to just the obvious benefits of taller structures, Mr. Guyton earlier talked earlier about collateral damage. When a tree falls and you have a wood pole, you have an age conductor, you often have damage and breakage. When we can rebuild the line with steel pipes, we have new high-strength steel conductor, we're much less likely to actually have equipment damage. We can remove the tree from the line, reenergize, restore. So less outage time and also less cost that ultimately will benefit the customers.

All right. I'm gonna move into our substation H&R project area.

From a substation perspective, we have a few different scopes of work that we're targeting. The first is our substation reliability upgrade scope. This is really when we have multiple different assets in the substation that have a need for upgraded replacement. So this can be circuit breakers, transformers, switches. It can also -- it typically also does include our system intelligence work, so we're bundling this work together, like I spoke about in the beginning.

But what we're doing is we're systematically upgrading this -- this equipment that is at end of life. At the same time, we're upgrading it to our latest standards, and this brings us reliability benefit for the customers directly served from this station, and also from the transmission lines for our transmission-level stations, and those are more of our stations that are 230 to 100 kV, 100 kV to 44 kV. They help distribute that transmission throughout the transmissions network.

Our air-break switch scope. This is a specific project targeted at a technology or a design called an air-break switch. This is used in our 44 kV and our 100 kV locations. It is on the high side of a power transformer. And really what it is designed to do is interrupt a fault and protect the power transformer from damage.

In a substation, the most expensive and the most critical asset is the power transformer, and when the transformers fail, they often result in a catastrophic failure; collateral damage to adjacent equipment, potentially for release of oil. So it's very important for us to protect them. The air-break switch is a device that projects them.

What we're doing is actually upgrading these with a device called a circuit switcher.

That has a better -- an improved ability to actually interrupt the fault and project that downstream transformer. So we're systematically replacing these. Ultimately, more reliability to project those critical assets in the station, which are those transformers.

We are also targeting animal mitigation scope upgrades. Next to vegetation or tree outages, animals are the number two driver for customer outages from transmission system outages, so just below the trees. So animal-resistant fences are a great improvement. They keep the snakes and squirrels and other similar-type animals, for the large part, out of stations, which is a great benefit, ultimately, for our customers.

One note I'll -- one note of difference from the DEP discussion and the prior technical conference, our security fence upgrade project that we had on the DEP, we actually -- we will have completed that project in DEC by the time the multiyear rate plan window opens. So we do not have any of that scope. So we've aggressively pursued that on the DEC side. That's just one difference I'll call out.

From a specific location, you can see some pictures here of a substation transformer and an oil breaker. We have upgraded our Winston tie station. This is an important tie station. It's just south of Winston-Salem. It actually connects 13 different 100 kV transmission circuits. So it's a key tie station for various transmission circuits. It also directly serves retail customers from the station as well. So we call that a combined tie and retail station. About 4,000 customers directly served off distribution circuits coming out of this station.

The project scope. We are upgrading the transformers to the current standard. We're upgrading the circuit breakers, which I will talk more to about those specific projects. We are also reconfiguring the station for redundancy. Right now it's a single-transformer bank. So if we do have a fault that occurs on one of the distribution circuits, if we have a problem within the station on a bus, we basically isolate all of the circuits, right, if the problem is associated with the high-voltage bus or the power transformer.

We are actually splitting the bank into

two separate power -- transformer banks. This allows us to actually cross-tie load between the two. We can take some circuits out for maintenance if needed, and we have some redundancy built in. So this reliability improvement, again, will benefit the customers served from this station.

All right. I'll move on. Our vegetation management project scope. Similar to what Mr. Guyton spoke to, this is focus on hazard trees or danger trees they are sometimes called. But these are trees outside of the right-of-way. I did mention this is the number one driver of customer minutes interrupted from the transmission system; about 17 percent of transmission outages from trees from outside the right-of-way. So we are specifically targeting those trees through an aerial inspection program.

We're actually creating what we call a tree canopy risk model. I'm gonna jump to the next slide so you could see an image of this. But what we do is we perform aerial inspection of our transmission system on a regular basis. We use a technology called LiDAR to actually scan these transmission lines. And what we're doing is we're looking for these hazard trees outside of the right-of-way.

So in the image on the right here, you can see on the middle of the right-of-way is the transmission circuit, and this is actually our High Point 100 kV circuit. There's a -- it's a dual-circuit line, so there's two lines actually running down this right-of-way. On the right and left side you can see the orange and red polygons, and these are created by our scanning software. Anywhere there's a colored polygon, we have a hazard that needs to be assessed in there. So this could be a particularly tall tree that, if it falls, it can fall onto our transmission line, or a tree of a particular breadth, that again, if it falls, it could impact our transmission line. So we are -- we are targeting these hazard trees and removing them before they actually cause a problem on the line.

I did mention this is the High Point 100 kV. It's a 37-mile line. It connects a hydroelectric plant to multiple different retail substations. It supports over 24,000 customers served off these two circuits.

The last thing I'll mention is we're really looking at the -- beyond the right-of-way. We're looking about 30 feet outside of either side of the right-of-way. And what we found is, under that amount of width, we can typically identify the trees that are gonna be potentially problematic, right, based on the right and some simple geometry, we can figure out what trees, if they fall, will create a problem on our transmission lines.

All right. The -- I'll move into our breaker -- circuit breaker upgrade project. Circuit breakers, I mentioned earlier, they take a signal from a relay and they open to isolate a portion of the transmission system. They need to operate very quickly, in less than a second, in order to really minimize the duration of the fall and have limited impact to our customers.

The current -- or the -- I'll say the legacy technology on the transmission grid is called an oil circuit breaker. It's really an oil-filled tank. That oil actually interrupts the arch that's created when that high-energy breaker operates. Of course, these are from 44 kV on the transmission side up to 500 kV, and then also the distribution-class circuit breakers in our substations as well. So 24 kV, 13 kV, those are also included under this program.

For those distribution levels, will replaced the legacy oil breaker with a vacuum technology breaker. And then for the high voltage, the current technology is a high-pressured gas circuit breaker. But these, combined with our relay upgrades, much more reliably and consistently interrupt those faults and ensure, again, that we're isolating that problem to the smallest portion on the grid. This is important, not just from an outage standpoint, but from availability of generation, especially as we have more distributed energy generation, around greater parts of the grid more circuits being impacted.

The last point on this slide I'll mention is we are specifically targeting the circuit breakers and prioritizing them. So we're looking at end-of-life assets, we're prioritizing based on field inspections, so the actual condition of the breaker, electrical testing that we perform periodically, the configuration of that breaker, and redundancies. So if the breaker fails, do we have a direct customer outage or do we have built-in redundancy? So that factors into prioritization.

And then number of fault operations. This is, essentially, how often does that breaker operate? What's the condition we expect from a wear perspective? Every time a breaker operates, you know, it wears to some degree, particularly with an oil breaker, based on that technology.

Specific project location I'll highlight for breakers is our Shelby tie station. In this substation, we have actually 14 circuit breakers included. So these include 44 kV, 100 kV, and 230 kV. This is a critical station in the Shelby area. We serve approximately 11,000 customers from the lines that actually emanate out from this station. So potential for a high number of customers to be impacted if we did have a failure event within the station. All right.

And the next project I'll speak to is our transformer upgrades. So similar to our circuit breaker upgrades, with our transformer project, we are targeting end-of-life assets. Our goal is to replace -- identify and replace that asset prior to failure. That allows us to do it on a proactive manner, to avoid an unplanned customer outage, and obviously to control our costs so we could most efficiently execute the replacement scope.

So a power transformer or auto transformer -- so these are just two different types of transformers. On the transmission grid, a transformer can change voltage levels from high voltage, say 230 kV, down to 100 kV. So those are critical at our tie stations as we move power around the transmission grid. And, of course, at our retail substations, taking the power from -- the voltage from a transmission level down to a distribution level and getting that power out to our distribution-served customers.

With a transformer, another key function of that transformer, in addition to these large voltage steps is voltage regulation. So many transformers have an included load tap changer, which is essentially a voltage regulator. It allows very small step changes in voltage. So like you heard earlier about voltage regulation, these load tap changers are very critical to ensure that we're, from the substation, sending out and controlling that voltage level, often within plus or minus 1 volt. Very tight bands.

And the load tap changer or voltage regulation component is often the location of a failure when we do have a transformer failure. We are actually upgrading that technology, again, similar to circuit breakers that uses an oil technology, the new regulation or load tap changer technology that would be industry standard now is a vacuum-based technology. When you have a vacuum changer within this load tap changer, you actually eliminate the possibility of arch gases building up and leading to catastrophic failure.

So I say all that to say our upgrade is not just resetting the life expectancy, it's really eliminating a significant failure mode for our transformers on the grid.

All right. A specific project location for transformer upgrades is the Concord, Maine, substation. We're actually replacing two transformers that have been identified in poor health through our monitoring and testing program. Each asset is over 50 years old.

In conjunction with this work -- so we're also upgrading some current limiting components, small ancillary components that are adjacent to the transformers, and similar to a line operating, this would allow future capacity enhancements as needed. So I just mention that to say, we're taking this time to opportunistically improve the system to allow additional capacity improvements, without having to revisit that same location, that same project scope, in the future. This will directly improve reliability for about 7,500 customers served from these transformer banks.

And then last thing I'll mention here is transformers are one of the top five leading causes of customer minutes interrupted. So transformer failures or transformer equipment leading to a failure and interrupting customer service.

All right. The final project scope on the transmission presentation today is our capacity and customer planning scope. So I mentioned early on, there is really three scopes of work here. One is serving our customer needs. So as we see load move around the system, as we see load growth, new customer connections, these are driven through this project.

Our NERC reliability standards are one of the key -- key obligations we have as a utility, so we perform system modeling, and we perform that modeling with certain failure scenarios, right, that the NERC standards dictate. So if we have certain segments of the transmission system that were to be out of service, what overloads would we have in other parts of the system? And many of our projects are driven by these planning studies, right, which identify the need for capacity upgrades, redundancy in some cases, sometimes we can have redundant relays or breakers that we can actually put in. So we are looking for the most efficient solution, if you will, to a problem that's identified through a planning study.

I mentioned those capacity upgrades are informed through the ISoP process. So if we do need the -- if we do identify a need to upgrade a substation, or say upgrade a transformer, that may be driven by a peak load condition that occurs during a very small window of time. You know, summer, middle of the day, highest load time, you know, that is where we have a constraint. So, for this reason, we are looking at what's the most efficient way we could address that constraint. So it's a relatively new process for us, but we're looking at those non-wire alternatives, battery storage. Are there other ways we can meet that peak demand and still meet our compliance obligations, without necessarily upgrading the transformer or replacing the transformer? So that is embedded in our evaluation process moving forward.

The last area I'll mention is our red zone expansion. Our transmission expansion planning or our red zone project. So, again, I know the Commission is familiar with these from the Carbon Plan proceedings, but these are areas of the grid where we have had numerous interconnection requests for new solar generation, and our interconnection studies have identified that these transmission circuits are at or near maximum capacity. They are not able to connect additional generation of significant magnitude without significant upgrade. So reconductoring large portions of the system.

So we actually have four transmission circuits included in our multiyear rate plan that are in a red zone in the DEC area, which is in the -- actually, the South Carolina service territory of our Duke Energy Carolinas location. And I'm gonna talk about a specific one of those on the following slide.

We are still in the process of working through the North Carolina transmission planning collaborative, which we did present these projects to, to obtain stakeholder input, and that would be in alignment with the FERC-approved process for local transmission planning. So I just mention that as well. We do expect a vote in the December timeframe for the next version of our local transmission plan, which does include this work.

One of these -- really two of the project locations I'll highlight is the Lee and Piedmont 100 kV line-up rates. So you can see in the pictures on the right and left, these are parallel transmission circuits. So they both start and end at the same location. So on the south end, the W.S. Lee combined cycle plant, and then the north end is the Shady Grove tie station.

So both of these transmission circuits are approximately 12 miles. So it's a 24-mile total uprate, and what we're doing is we are rebuilding with a higher capacity conductor. We're approximately doubling the available capacity for these lines from that -- from a current carrying standpoint. Obviously, new structures, based on the latest standards from a loading standpoint, both electrical and structural design standpoint.

What we're really seeing is the build-out of solar resources, kind of south and west of this area, is driving this need. Mentioned earlier, multiple interconnection requests have identified that's lines as being constraints, and necessary for uprate in order to connect more solar to the grid.

But in addition to that, these lines -- we see significant reliability opportunities, reliability improvement through the uprate of these lines. We have towers on these lines that are over 100 years old. We have copper conductor, which, of course, the standard for a long time has been an aluminum conductor with steel reinforcement. And so in addition to enabling our expansion of renewable energy resources, we're improving the reliability through reducing the chance of equipment failures, actually leading to interruptions for the grid. So it's important for us to be able to move our generation resources in solar from one part of the grid to the other, and, of course, the customers that are served through the interconnecting lines and stations from these two lines.

All right. And at this point, this completes the transmission presentation. I'll take any questions at this time before I pass it along to Ms. Meeks.

COMMISSIONER DUFFLEY: Thank you. I think, at this point, we're gonna take an afternoon break of 10 minutes. So let's come back at 3:16.

(At this time, a recess was taken from 3:06 p.m. until 3:17 p.m.)

COMMISSIONER DUFFLEY: Chair Mitchell?

CHAIR MITCHELL: Just a few more questions for you-all. The end-of-life asset -- end-of-asset-life programs you mentioned, are you using asset life based on depreciable life, or how do you-all define end-of-life?

MR. MALEY: Yes. The -- I don't know that we have a succinct definition, per se. What we're seeing is assets that, yeah, they're at the end of their useful life. They're based on similar characteristic, make, model, experiencing in-service failures. So it's primarily based on work experiencing in-service failures of this similar type asset, and we need to -- we need to --

CHAIR MITCHELL: Okay.

MR. MALEY: -- start replacing other similar-type assets.

CHAIR MITCHELL: Sounds like less of an accounting definition and more of a what's actually happening.

MR. MALEY: Correct. It's more of an asset management definition.

CHAIR MITCHELL: Got it. Okay.

MR. MALEY: Yes. Correct.

CHAIR MITCHELL: Okay. The -- at this point in time, are you-all able to use any sort of automation for your asset monitoring, like I've read about programs that involve compilations of photography, for example, of transmission assets, and so then you could -- I think the way these programs work is you send cameras out, you send drones out, and the drones would photograph your assets and then could tell you or predict where the problems are? I mean, are you-all there yet?

MR. MALEY: We are in early stages of doing some of that. So one example is our aerial patrol program. So I mentioned it for vegetation, but in addition to vegetation, we perform aerial patrols of all of our transmission lines looking for asset issues, right? So we have integrated with that a camera technology that actually can take high-resolution images of specific problems on -- you know, associated with the conductor, with insulators, with the towers, themselves. So we do -- we have that integrated in our aerial patrol program.

What we do is we flag locations, and then we'll go back to that location and use a drone if we actually need higher resolution imagery. The ultimate vision is yes, take the -- take the aerial photography and video stream from those flights and actually process it through a machine-learning platform. So it can more readily tell us, you know, go here, here, and here. We are still at the stage of, there is a lot of manual work to identify those specific locations, but absolutely, it is something that we are investigating and actively working on that technology, working with several different vendors or manufacturers, you know, that specialize in that area.

CHAIR MITCHELL: Okay. Just a curiosity of mine. I didn't know how -- if that was, sort of, a real-world application at this point in time or not. So it sounds like you-all are working in that direction.

MR. MALEY: Yes.

CHAIR MITCHELL: Last question. How much or how many of the projects that you-all have proposed in this particular rate case proceeding relate to generation asset retirements?

MR. MALEY: Generation -- so for the transmission-specific project locations, we do have -- we do have some work that's associated with generation retirement. So one example is our Allen steam station. So as part of that retirement, we're moving the switch yard to a new location. So it's a multiyear project. We actually have some early phases -- we have some projects going on now, we have additional phases of the project included in our multiyear rate plan. So there is some of that, but I'll say it's a smaller percentage of our transmission projects.

CHAIR MITCHELL: Okay. Should we anticipate -- just following up, should we anticipate seeing more in the next -- in the future rate case? I mean, I'm just kind of trying to understand timing here.

MR. MALEY: You know, I have a difficult time projecting that. I will say some generation requirement -- retirements really result in very minimal changes in the impacts to the transmission systems. We are able to keep the switch yard at the current location, or, you know, the substation that's essentially onsite at the generation plant. We can still use that as an asset to route power, just without the associated generation coming on.

You know, Allen is an example where that didn't work, for some specific reasons, under our planning model. We needed to actually move that. But I wouldn't say that every generation to retirement requires a significant project scope on the transmission grid. There will be some changes, but it's not necessarily significant changes.

CHAIR MITCHELL: Okay. That's helpful. I appreciate that explanation.

COMMISSIONER DUFFLEY: Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Good afternoon. I noticed, under the breaker upgrades, you have information here about circuit breaker technologies transitioning to FS-6 gas circuit breakers.

As we move more to electrification, I thought we were -- that Duke, in particular, was trying to back away from FS-6, that it was a more potent greenhouse gas. Can you comment about that?

MR. MALEY: Sure. Yeah. Great question. Yes. For high-voltage circuit breaker applications, the industry standard still remains FS-6. Duke Energy is very interested in exploring alternative technologies. There are several technologies that vendors are starting to come out with. There are several that are commercially available that I'll say the -- you know, the 115 kV voltage levels, 100 kV voltage levels, I've seen some up to 145 kV class. Particularly, when you get into the 230 kV, 500 kV circuit breakers, there really is not proven technology out there that we have at this point seen as an option to adopt.

So the vast majority -- the industry standard still remains FS-6 at this point. Although, again, like I said, we are interested in collaborating with industry on future opportunities to move away from SF-6 [sic].

COMMISSIONER BROWN-BLAND: So there would be emissions? This is not emission-free, in that regard?

MR. MALEY: It is true that any piece of equipment or component that contains pressurized FS-6 would have some off -- you know, some leakage, small amount of leakage. Typically it's very small. With the new asset, you know, we can really control that, as long as it's in good condition, we perform regular inspections, you know, there is no quantifiable -- you know it's a de minimis type leakage.

As those assets age and degrade and -- you know, there can be problems with that, but we address that under our maintenance program, our substation inspection, and our circuit breaker maintenance program. So we do have programs in place to minimize the amount of leakage from pressurized FS-6 components.

COMMISSIONER BROWN-BLAND: And so my general understanding, it hasn't been a major concern, because it's just not the volume we see with carbon, but that it was more potent, but -- but I guess that's my question. As we go towards electrification, would we expect to see a greater volume here or more concern with FS-6?

MR. MALEY: So I think -- I'm not an expert in this area. I'll generically say, you know, yes the sort of the greenhouse gas contribution, I would say, from transmission equipment filled with FS-6, yeah, it's very small compared to, of course, generation plant-level impacts, right; burning coal, things of that nature. But it's a small contributor, but again, something that Duke Energy sees as an important area that we can adopt industry best practices and eventually, hopefully migrate away from that technology. But at this time, it does not exist as an opportunity to migrate away from that technology on a large scale.

COMMISSIONER BROWN-BLAND: Thank you.

COMMISSIONER DUFFLEY: Commissioner Hughes?

COMMISSIONER HUGHES: Yes. Could you briefly comment on any overlap or relationship between the cost estimates, particularly your bar that shows the different segments, and then the adders that we -- that we were presented with during the Carbon Plan, the transmission adders that went. Is there connection -- you mentioned the red zone, but are there other connections?

MR. MALEY: Unfortunately, I'm not familiar with the adders -- transmission adders or the specific item you're referencing from the Carbon Plan testimony. Can you elaborate on that? I may be able to --

COMMISSIONER HUGHES: Well, it was my understanding that that -- a segment of transmission projects that would be needed to implement the new generation portfolios were analyzed, and somehow there was a series of adders that were put on, so as a -- as new generation went in, there were transmission costs that followed along, based on an adder, which I interpreted were based on some planning. And it just seemed like some of these projects you did make reference to new generation, but quite a few didn't, so I was just curious what the overlap would be. But if you're not the best person to talk about it, we could --

MR. MALEY: Yeah. I'm not familiar with the adders. I guess the comment I'll just reiterate here is yes, the red zone projects, they are a key portion -- or they are a key transmission portion of our Carbon Plan. Of course, those capacity uprates enable additional generation to be connected, and that's really all under that capacity and customer-planning piece. I'd say if there was any overlap, it would be limited to the capacity and customer-planning program, and probably more specifically, the subscope involving the red zone projects.

COMMISSIONER HUGHES: Okay. Thank you.

COMMISSIONER DUFFLEY: Commissioner McKissick?

COMMISSIONER McKISSICK: And let me follow up briefly what Commissioner Hughes was requesting, in terms of information.

You identified there were four circuits in South Carolina that are included, you know, among the products that are part of what you're gonna be carrying out.

Are there other projects that are not currently part of what the collaborative just kind of looked at -- that you anticipate would be moving forward and included in what comes to us.

MR. MALEY: Yes. I understand the question. At this time, no. For Duke Energy Carolinas region, these are the -- these are the only ones --

COMMISSIONER McKISSICK: These are the only ones.

MR. MALEY: -- that are in our -- I'll say our current or near-term scope that we're pursuing.

COMMISSIONER McKISSICK: Okay. And let me shift gears a little bit. And that's going over to the -- I guess the pole replacement. You are putting in the lattice steel in some areas.

How do you go about identifying those areas that are best suited for putting in the lattice steel and removing the wooden poles? I mean, certainly, failure is a component of it, but it seems that once you go out and start replacing them, you got to replace them in mass numbers, rather than just in isolation.

MR. MALEY: Yeah. So the -- depending on the voltage level, we have very, kind of, specific current designs, and actually the wood pole replacements are all on our 44 kV system. So that's really where the system was built out with a wood pole infrastructure. We're replacing those with steel poles.

The lattice towers are really at our 100-kV-and-up level, and we're targeting the locations near those uprates based on our condition-based inspection program. So aerial patrols, in addition to ground-line inspections. We are -- we can generally identify regions where we have corrosion rates that may be higher than other areas. That may be due to the soil condition, the water table level, the specific environmental constraints. So in addition to the degradation rates, the areas that may be particularly hard to access. So if we have a failure, it's hard to access this area.

Mountainous terrain, swamp terrain, things like that, that's where we would, from an asset management standpoint, look at what kind of work do we need to target in this area to improve the resiliency on the grid.

So cathodic protection is a key project we have for the -- specific to the lattice towers. What is not included in the project scope is a lattice tower replacement project. That would be really one off for specific cases where really there was severe damage, but that's not being addressed at a wide scale. It's the wood poles at the 44 kV, and then it's life extension through corrosion mitigation of the lattice towers.

COMMISSIONER McKISSICK: Got it. Thank you. And I do appreciate your presentation. It was very thoughtful and very informative.

MR. MALEY: Thank you.

COMMISSIONER McKISSICK: So I appreciate that.

COMMISSIONER DUFFLEY: Commissioner Kemerait?

COMMISSIONER KEMERAIT: Yes. I have one question about the benefit portion for your capacity and customer planning project. And for capacity and customer planning, I think there were two components, the NERC reliability component, and then also the red zone upgrade project.

So for the red zone projects, how were you -- how did you assess or determine what those -- what the benefits would be?

MR. MALEY: Great question. And we had some maturity in that approach since the DEP tech conference. So you may recall me talking about, yes, we don't -- at this time, we don't have a way to quantifiably display or calculate the benefits for the expansion of solar energy or renewal energy resources. We are performing the benefit-to-cost ratio based on the reliability portion of the benefit.

So we are evaluating these circuits based on their -- based on a condition assessment. So factors such as we have towers that are over 100 years old, legacy copper conductor designs. So we're actually modeling like an asset management project. What is the probability of failure of these circuits based on the condition that the components are in? And then what will be the benefit to the customers and to the grid by avoiding that failure? So that's our approach.

COMMISSIONER KEMERAIT: Okay. Just the NERC reliability impact?

MR. MALEY: Yeah. Pure reliability and -- not necessarily NERC, specifically, but I'll say primary customer reliability benefits, right. That's really what the ICE calculator drives out. If this fails, here is the cost of that outage.

COMMISSIONER KEMERAIT: Thank you.

MR. MALEY: Sure.

COMMISSIONER DUFFLEY: So thank you for your presentation today. I have one follow-up to Chair Mitchell's question about end-of-life.

So I heard you respond that the end-of-life may be different depending on the asset. So one asset might be 20 years, one asset might be 10 years.

Do you keep a database of what the end-of-life years for each asset or --

MR. MALEY: The -- our asset management experts, although I'm not aware of a specific database, they do have information for various types of assets on the expected life from a --

again, from an asset management and reliability standpoint. So I don't know that it's documented in a database, but I'll just give a few examples.

So a device with electro- -- or with circuit breaker -- excuse me, circuit board components, such as a digital relay. This is something we've had to learn as we installed more of these modern devices with printed circuit boards. We expected about a 20- to 25-year life of these assets. That's different than some of the legacy components. So that is being factored into our long-term planning. And again, the example I shared earlier with breakers, transformers. We're really looking at, when are we starting to see failures that are driven from age-related failures.

So I guess to reiterate, I'm not aware of a specific database, but the experts in those areas do have a good grasp on the expected life for various classifications of components.

COMMISSIONER DUFFLEY: Okay. Thank you for that. And then Chair Mitchell also touched on this. I have a staff question for you, so I'm just gonna read it.

Several RZEP projects are included in the transmission projects; however, Marshall McGuire 230 kV line upgrade, which is necessary to the Marshall coal plant retirement, does not appear to be included here.

Why is this project not included, and when should the Commission expect these projects to be implemented? And if you could, state whether this project is slated for beyond 2026.

MR. MALEY: Could you state the name of the project again, please?

COMMISSIONER DUFFLEY: Marshall McGuire 230 kV line upgrade.

MR. MALEY: (Presenter peruses document.)

Just confirming that it is not on my list. So, yeah, I cannot speak to the specifics of that project. It is not included, as stated in our current multiyear rate plan portfolio, but I do not know the future in-service date for that.

COMMISSIONER DUFFLEY: Okay. Thank you.

MR. MALEY: Sure.

COMMISSIONER DUFFLEY: Any other questions before we move on?

(No response.)

COMMISSIONER DUFFLEY: Thank you.

Ms. Meeks?

MS. MEEKS: Yes. Good afternoon, all. My name is Laurel Meeks, and I'm the director of renewable energy development, and I'm pleased to be here with you today discussing energy storage benefitting the distribution grid.

Today, I'm first planning to discuss grid use cases of battery energy storage, specifying which grid uses are highlighted today within the technical conference. Then we will turn our attention to project identification processes, how we have performed our cost-benefit analysis methodology. Then we will dive into more detailed program descriptions, and highlight specific costs and benefits of each program type, or category as we refer to them in later slides.

So let's first dive into the grid use cases of battery energy storage. From a grid operator perspective at Duke Energy, we know that storage is a very exciting technology that serves as a sort of Swiss Army Knife. And what I mean by that is a single energy storage project can be utilized to perform multiple grid functions, although not necessarily at the exact same time.

In fact, the Duke Energy development approach is to cite projects in order to stack or layer multiple grid services, which maximizes the customer benefit. You will see that described for each of the projects or programs highlighted later in the presentation.

This pie graphic attempts to summarize what different configurations of energy storage can do, in terms of grid services. So within the interior circles, we distinguish siting energy storage, either at the customer location, standalone and interconnected at the distribution voltage, standalone and interconnected at the transmission voltage, or sited adjacent to a generator.

The exterior circle then demonstrates the grid function that different siting strategies can support. And those are grouped by which Duke Energy business unit or customer is most interested in that benefit.

From a production or generation standpoint, energy storage can be utilized to capture excess energy production and dispatch it when energy demand is highest, or to perform resource adequacy or serve system capacity, which is typically a focus of the integrated resource planning process. From a transmission operations perspective, operator-controlled energy storage could provide minute-by-minute balancing between load and generation as an ancillary service. And for both transmission and distribution planners, energy storage can be a cost-effective alternative solution by deferring or avoiding traditional wires investments in order to improve local reliability or increase local capacity.

Today, we are here to discuss battery energy storage applications that will benefit the distribution grid. Both categories or programs in discussion today will also benefit the bulk electric system, the generation fleet or transmission system, when not in use for their primary function. And that offers that maximum customer value that I elaborated on earlier. Visually, we can picture these storage systems sometimes cutting across that highlighted pie slice to serve the generation and transmission operations functions.

So we're gonna discuss how grid services translate to customer benefits in later slides, but for now, I'd like to summarize that storage enables increased renewables penetration through balancing services. This technology also offers reliability and resiliency for customers and our communities, especially critical customer services. It enables efficient grid operations and flexibility for the dynamic energy transition.

Went a little too far there. In this presentation, I highlighted that storage enables increased renewables for penetration, reliability, and resiliency for communities and critical safety services, efficient grid operations, and flexibility for the dynamic energy transition.

Well, what does that mean for customers? Well, first, this technology provides environmental benefits for DEC customers across North and South Carolina. Grid services, such as capacity, regulation services, and contingency reserves have traditionally been performed by carbon-emitting generation resources. Replacing carbon-emitting resources with assets that have the ability to store and redeploy clean energy resources helps reduce emissions and deliver positive environmental benefits.

Storage is inherent to the clean energy transition. An investment in energy storage is critical to enabling the sustainable growth of renewable energy, and that's because it balances intermittent and renewable generation so that customers maintain access to the safe affordable and reliable power that they count on.

Furthermore, this is a novel technology. At Duke Energy, we're building off a decade of experience operating distributed energy resources. Nonetheless, as customers demand new grid technologies, the utility processes for design, study, interconnection, implementation, and operation will need to become more and more refined.

We know that energy storage is a part of prudent utility planning and our low-carbon future, and at Duke Energy, we will leverage the use cases in the DEC multiyear rate plan portfolio to improve our processes with high customer value added projects. A programatic approach will also allow the utility to leverage the supply chain creating lower-end cost to customers as the fleet diversifies and scales to support the energy transition.

This slide will highlight the overnight capital costs associated with the battery energy storage investments discussed in the technical conference.

Meeting clean energy transition goals requires new technology and a new way of operating the grid. Energy storage will be a critical resource for balancing the bulk system, as well as serving traditional transmission and distribution needs. The battery energy storage portfolio referenced in the technical conference today is a portion of the fleet, helping to achieve the energy transmission objectives, and that will be included in the multiyear rate plan. This portion of the battery energy storage fleet, supporting both the distribution system and the production system in DEC, represents a total of $83.5 million in overnight capital costs across the multiyear rate plan period.

Currently, Duke Energy has plans to

utilize battery energy storage to make improvements to the distribution grid within two primary categories or programs, reliability and critical community customers.

Before we dive into the energy storage programs themselves, let's take a moment to highlight how particular projects are identified. The energy storage development team adheres to Company project governance practices and uses a value-based approach to funnel the most prudent projects from origination through to operation.

In the project origination phase, grid needs are screened with a data-driven approach to identify whether a battery energy storage solution is the best solution to the local grid need. Then, a preliminary and subsequent detailed engineering analysis optimizes the most cost-effective solution sizing and siting for that grid need.

Energy storage is a new technology and tool that offers solutions to grid needs that the approval did not have. Duke Energy's excited to use this technology to benefit customers and is working with ISoP and system planners to understand the proposed uses and benefits for each project.

Each project highlighted in the DEC technical conference is ISoP-informed, including both a technical and economic screening while projects move through the development cycle.

Reliability batteries are identified as potential solutions on remote distribution feeders with load pockets at the tail end of the feeder, and critical community customer batteries are identified for critical facilities which support community needs, such as hospitals, fire stations, and more, where traditional reliability improvement strategies are difficult.

Our cost-benefit methodology is highlighted on this slide. At a high level, it's important to note that, for the projects highlighted today in the technical conference, Duke Energy used an approach similar to the methodology for the Hot Springs battery-approved CPCN. This means we used avoided transmission and distribution costs to quantify local customer benefit. The Company presents these CBAs on a net present value of revenue requirement basis. Specifically, so that we can capture customer benefit of the newly enacted standalone storage ITC.

To form the CBA, we began with three major inputs. First, battery sizing in both megawatt and megawatt hour is critical for forming system cost of capital and O&M. Second, a transmission and distribution alternative analysis is performed to identify which theoretical alternative could have been utilized to solve the local grid need. And importantly, these alternatives are called theoretical because, in reality, the alternative would likely have been infeasible to execute. And third, ISoP grid proxy values are input to determine the production value of the energy storage system.

Within the CBA development process, we use initial deployment costs which have been formulated from recent real time market cost data from vendors, which reflects the inflationary and geopolitical pricing that has an impact on clean energy technologies. We also utilized battery refresh costs in year 15 to replace degrading battery cells and overall long-term O&M costs to form that net present value of revenue requirements. These are then contrasted against the aggregated net present value of benefits of avoided costs for theoretical transmission and distribution investments that would have been solved -- or would have solved the local grid need -- bulk system proxy values, and the impact of realizing that future tax benefit from the standalone storage investment tax credit.

Notably, the ITC does not offset actual capital cost, so using a CBA based on that net present value of revenue requirements is the best way for us to reflect customer benefit from these federal incentives.

Our final output is an Excel model, which was included in the technical conference filing, and we're happy to add that, within these documents, a sensitivity analysis has been conducted. This shows how variance in either system costs or benefits could ultimately reflect changes to that cost-benefit ratio.

So let's dive into our energy storage programs now. The reliability-type projects within the battery energy storage program improve reliability and resiliency to avoid outages and speed restoration, while at the same time enabling cleaner energy options at the bulk electric system level. The image on the screen shows a scenario where geographic features and service territory assignment boundaries have created an enclave of customers where Duke Energy has limited feasible options for improving reliability. In these areas, traditional reliability improvement strategies, such as an alternate or back-up feeder, may not have been feasible. Instead, a microgrid based on a single large battery sited adjacent to those targeted customers may be the best solution. With a new battery and related interconnection equipment, if there is a loss of utility service, the battery will form a microgrid area and serve customers' electrical meters until repairs are made to restore normal service. These designs are optimized to economically mitigate a significant number or more than 90 percent of the outages each particular microgrid area has historically experienced over a period of years.

Battery designs have been optimized to create the most improvement and reliability for the least cost to customers. And when not in use for reliability and resiliency, recall these systems will dispatch to provide services, such as capacity, energy arbitrage, or system balancing supporting the grid as it transitions from legacy generation types to more renewable resources.

We'll move on to the slide documenting the costs and benefits of this particular program. Before I begin, it's really important to note the tools for quantifying the costs and benefits of this nascent technology are new and evolving. While some benefits of this clean energy technology can be easily captured, benefits such as sustainability and resiliency are subjective and notoriously difficult to put a dollar figure on. Quantifiable and nonquantifiable benefits are, therefore, highlighted on this slide.

Using battery energy storage technology for reliability and resiliency in a microgrid configuration, helps ensure continuity of business activity for many hours in the year when they would otherwise stop due to service outages. This means that the North Carolina economy is more resilient alongside the electrical grid. And for residential customers, this technology makes sure that electricity is more rapidly restored so that air conditioning, refrigerators, or computers can all still run. This translates to save customer costs on things like spoiled food or loss from in-home office productivity.

Because these microgrids serve entire communities during outages, they also support basic services, such as cell towers or stoplights, which are safety features.

This microgrid technology application also gives distribution planners a tool to solve a grid issue which previously did not always have a viable solution. This is a prime example of how technology advancement can benefit utility customers. Energy storage in this context is referred to as a non-wires alternative. These batteries are the most cost-effective and implementable solutions.

To provide the quantifiable benefits, we compared the costs of those alternative traditional solutions to increase reliability that were assessed to have the highest likelihood of being implementable, but still may ultimately have been unexecutable due to challenges related to permitting, real estate encumbrances, and service territory assignments.

Because these batteries also provide bulk system benefits, we include the value for these production services. So that represents a total of $62.9 million in total net present value of revenue requirement benefit to customers, contrasted with the total net present value of costs requirement of cost at $66.8 million, which represents a 0.94 benefit-to-cost ratio.

Importantly, we did not factor in ICE values to the cost-benefit ratio, but we have performed those calculations, and they resulted in roughly $30 million of customer benefit, not including major-event days, and roughly $50 million of benefit to customers, including major-event days. We did not feel like it was appropriate to stack the traditional T&D deferral values with the ICE values, knowing that would be double counting.

Moving along to our next program, critical community customer batteries can be used to support reliability and resiliency for critical services such as hospitals, police stations, or evacuation shelters.

Some critical community functions, such

as hospitals and emergency response centers, also reside where geographic features and service territory assignment boundaries have created enclaves where alternate service feeders or other traditional reliability solutions are extremely difficult to site. As depicted in this image on this slide, a hospital is out in the tail end of an isolated distribution feeder, and a battery or microgrid sited adjacent to the customer center was the best solution to increase reliability and resiliency.

With a battery and its new related interconnection equipment, if there is a loss of utility service, the battery will form a microgrid area and serve the customers' electrical meters until repairs are made to restore normal service. These systems also simultaneously enable cleaner energy options at the bulk electric system level to the benefit of all grid customers.

When not in use for reliability, these systems will dispatch to provide services such as capacity, energy arbitrage, or system balancing support as the grid transitions from those legacy generation types to more renewable resources.

And we'll transition to cost-benefit slide for this program as well. Similar to the reliability program batteries, tools for quantifying the costs and benefits of the critical community customer program and batteries, in general, are new and evolving, so there is benefits, again, such as sustainability and resiliency, are subjective and notoriously difficult to put a dollar figure on.

But first and foremost, this category of batteries enhancing public safety. Keeping the lights on at these facilities means that our communities are safe and healthy in the event of an emergency, which is a benefit to everyone. In fact, providing reliability and resiliency in times of service outages could be the most critical time that customers would need this community service. Think of a scenario where we faced a bad hurricane and your community needed bad medical attention. We would want that hospital more than ever.

Secondly, this is a new customer offering that customers are increasingly needed for circumstances where both cost and benefit can be shared between all DEC customers and that critical community service provider. With this project category, the customer could make use of valuable land and interconnection infrastructure. Those are features that could make this project a possibility. And they could also plan other ways to share costs with the utility.

Engineer storage here is also referred to as a non-wires alternative. These batteries are the most cost-effective and implementable solutions. To provide the quantifiable benefits, we compared the costs of alternative traditional solutions to increase reliability that may or may not have been feasible to implement, and because these batteries also provide those bulk system services, we layered in the value of those production services. That represents a total net present value of revenue requirement of benefits of $7 million. The costs include both overnight capital investment, that replacement and refresh cost, as well as O&M cost, and that represents a total net present value of revenue requirement cost of $7.2 million, representing a cost-benefit ratio of 0.98.

So with that, I've covered quite a bit

of material today, including your energy storage grid use cases, our project identification approaches, CBA methodologies, and highlighted the program summaries I'd like to either turn it over to Brent or leave some time to answer questions. We've just got one slide left to summarize.

COMMISSIONER DUFFLEY: Okay. Well, thank you. Let's see -- excellent presentation. Let's see if there are questions for you.

Chair Mitchell?

CHAIR MITCHELL: So I'm interested in the critical customer program you just described.

Can you just -- can you explain a little bit more what the -- what you-all are proposing here? Specifically interested in any cost sharing that you-all might have thought through. So can you just talk some more about that.

MS. MEEKS: Yes. Again, these are opportunities for when customers are requiring new energy solutions and had the opportunity to share in cost and benefit with the utility. So this is a new and nascent program. The particular, you know, figures around sharing costs are still in negotiation and evolving, but in this particular scenario, we've asked that the customer share and provide valuable land and interconnection features, and we're exploring other ways to share costs with this critical community service provider.

CHAIR MITCHELL: Okay. So this would be an instance where the customer comes to the Company and says, "We need some additional -- we need additional support from the Company in the form of energy storage or additional generation," and this would be one solution to that type of customer request; is that what I'm understanding?

MS. MEEKS: Yes. It's a new tool in the toolkit, and it's specifically provided for those critical community customers which provide that regional safety benefit for DEC customers.

CHAIR MITCHELL: Okay. Are you-all -- does the Company define critical customers, or are these self-selected customers that come to the Company and say, "We have a need for you-all to meet"?

MS. MEEKS: I believe that we do have tiers of customers that demand higher-than-average reliability and resiliency, and I'm not an expert on how we tier those customers.

CHAIR MITCHELL: Okay. All right. I'll stop there. Thank you.

COMMISSIONER DUFFLEY: Commissioner Hughes?

COMMISSIONER HUGHES: I think you mentioned a little bit the impact of the ITC on these, but if I understood from the introduction, these analyses don't take into consideration anything that might have happened with the IRA, the Inflation Reduction Act credits, or do they?

MS. MEEKS: Yes, they do. So just to clarify, the standalone storage investment tax credit was a part of that recently enacted IRA bill. So while the standalone storage ITC tax rules are still being figured out, and that standalone storage ITC market is evolving, we're gonna continue to look at how we could maximize benefits of those investment tax credits on behalf of customers. That's evolving, and we've made some assumptions within these CBAs of how that may look out in the future.

COMMISSIONER HUGHES: So there are some assumptions here?

MS. MEEKS: Yes.

COMMISSIONER HUGHES: Because it seemed like a lot of your analysis was compared to the traditional, I guess, wires approach, and so you did that comparison with those assumptions imbedded?

MS. MEEKS: Yes, that's correct. So on the benefit side, we layered the benefit of a future-realized investment tax credit -- which, by the way, is a very conservative assumption if you were to dig into the CBAs -- the value of avoiding that traditional T&D investment, and then also the value of providing the production benefits and services.

COMMISSIONER HUGHES: Okay. Thank you.

MS. MEEKS: Thank you.

COMMISSIONER DUFFLEY: Commissioner McKissick?

COMMISSIONER McKISSICK: Just one or two questions. And thank you. You did provide an excellent presentation, so I appreciate that.

In terms of the $83 million right now, it sounds as if there is not a defined set of programs that this would be used on. I mean, it's not as if there's -- they have already been identified, where you used engineer storage or either a microgrid with energy storage or energy storage standalone; is that a correct assumption?

MS. MEEKS: No. I would say that our projects are discrete and identifiable, and these programs represent each of the projects that will come forth within a multiyear rate plan filing, and they are either reliability-based in nature or the critical community customer.

COMMISSIONER McKISSICK: And how many projects would you anticipate that we may see?

MS. MEEKS: There are three projects that fall within these programs.

COMMISSIONER McKISSICK: Three that fall within each of those categories you are saying?

MS. MEEKS: Three that fall within both categories.

COMMISSIONER McKISSICK: Okay. Got it. And the one that Chair Mitchell was talking about, the cost-sharing program, is Duke Energy, in any of its other states that it's operating in, are they using that type of approach now, if you know?

MS. MEEKS: Yes. We have explored that for other critical community facilities, and one example of that is our Camp Lejeune battery, which has recently been filed within the Duke Energy Progress rate case, where we are providing a battery energy storage system, and Camp Lejeune has provided access to valuable land, and we're serving all Duke Energy Progress customers through the bulk system services with that battery, and it will be also utilized in times of need to support resiliency for that military base, which supports roughly 1,800 homes, I believe a hospital, a gas station, and daycares.

COMMISSIONER McKISSICK: Thank you. So I guess the last question would basically be, in terms of getting these funds to be, I guess, utilized most effectively, I mean, when it comes to those community-service-type projects, how do you identify which ones are the most meritorious?

I mean, you know, I can see where a hospital might fall, but certainly some of the other things that fall underneath that category may not be as meritorious, in terms of allowing for that type of participation to occur. So how is that done? I mean, you know, I notice you had doctors' offices under that category, but not all doctors' offices are in need of emergency services or, you know, back-up batteries, or be a part of a microgrid.

MS. MEEKS: That's a good question. And what I'll say to that is that our system planners, engineers, and developers are the experts, and they make certain that we have selected energy storage as the appropriate solution for the local grid need at hand. So we are accustomed to providing a higher level of reliability and resiliency for critical customers that are tiered in some fashion that I'm not intimately familiar with, and where a traditional transmission and distribution solution is not a possibility, we would explore battery energy storage or microgrid.

COMMISSIONER McKISSICK: And lastly, other than the projects that might be forthcoming, if there was a development somewhere that was interested in doing a microgrid battery with storage, is that something you would entertain as falling underneath this envelope of funds, or appropriation of funds that have been identified, or would that be separate and independent?

MS. MEEKS: Just to make sure I'm

answering correctly, in terms of the development, to fall within this critical community customer --

COMMISSIONER McKISSICK: Well, outside the critical customers category.

MS. MEEKS: Okay. Then no, it would not fall within this program type.

COMMISSIONER McKISSICK: And with the critical customer outside of North Carolina, have you seen any experience with or observed any experience?

MS. MEEKS: Yes. I will say that we have utilized cost-sharing and benefit-sharing mechanisms with regulated energy storage projects in our Duke Energy Indiana territory as well.

COMMISSIONER McKISSICK: Indiana.

MS. MEEKS: Yes.

COMMISSIONER McKISSICK: Thank you.

COMMISSIONER DUFFLEY: So going back to the reliability prong, you mentioned you were discussing non-wires alternatives, and where wires might be infeasible, and you listed some examples, one of which was service territory assignments. Can you expand on that for me, please?

MS. MEEKS: Yes.

COMMISSIONER DUFFLEY: Or give an example.

MS. MEEKS: And I'll say that I'm not a distribution planning expert, but what I can say is that our service territory assignments have created locations where there is enclaves, where we serve a load pocket at the tail end of the feeder, we're surrounded by non-Duke Energy territory, and we can't expect that non-Duke Energy customers would provide us the encumbrances in order to cross through that territory and provide a traditional transmission or distribution solution that would solve that same reliability need.

COMMISSIONER DUFFLEY: Okay. Thank you. Any other questions?

(No response.)

COMMISSIONER DUFFLEY: Thank you, Ms. Meeks.

MS. MEEKS: Thank you. Let me turn it back over.

MR. GUYTON: So I'll close us up here. We shared a lot of information today in the technical conference, as well as our prefiled materials highlighting energy storage, transmission and distribution projects. The projects both maintain and work together complimenting each other, building the foundation for an increasingly dynamic grid that supports two-way power flow, increased automation, as well as situational awareness, enabling the clean energy transition.

The projects we highlighted today will increase grid resiliency, safely expand renewables and distributed energy resources, and provide equitable access to benefits for customers. We do appreciate your time today.

COMMISSIONER DUFFLEY: Well, thank you for coming today. We appreciate all of your presentations. One last call for questions?

(No response.)

COMMISSIONER DUFFLEY: Seeing none, thank you again. You-all may step down.

PANELISTS: Thank you.

COMMISSIONER DUFFLEY: Okay. And there are no other presentations. However, CIGFUR III filed a notice of intent to participate today. However, in lieu of a presentation, CIGFUR III requests that the Commission accept the documents attached to its October 17, 2022, filing labeled as CIGFUR III's Technical Conference Exhibit A and Exhibit B.

The Commission shall accept the documents attached to CIGFUR III's October 17, 2022, filing labeled as CIGFUR III's Technical Conference Exhibit A and Exhibit B as CIGFUR III's presentation today.

So are there any other matters before we adjourn?

MR. JEFFRIES: None that I'm aware of, Madam Chair.

COMMISSIONER DUFFLEY: Okay. So we've come to the end of the day. Thank you, and we are adjourned.

(Technical Conference concluded at 4:09 p.m. on November 2, 2022.)

CERTIFICATE OF REPORTER

STATE OF NORTH CAROLINA)
COUNTY OF WAKE)

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

This the 18th day of November, 2022.

JOANN BUNZE, RPR
Notary Public #200707300112