PLACE: Dobbs Building, Raleigh, North Carolina
DATE: Monday, July 25, 2022
TIME: 2:00 p.m. - 5:18 p.m.
DOCKET NO.: E-2, Sub 1300
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.
Commissioner Karen M. Kemerait

IN THE MATTER OF:

Duke Energy Progress, LLC's Request to Initiate Technical Conference Regarding the Projected Transmission and Distribution Projects to be Included in a Performance-Based Rate-Making Application

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P R O C E E D I N G S

CHAIR MITCHELL: All right. Good afternoon. Let's go on the record, please. I'm Charlotte Mitchell, Chair of the Utilities Commission and with me are the following Commissioners. When I call your name, please announce your presence. Commissioner Brown-Bland?

COMMISSIONER BROWN-BLAND: Present.

CHAIR MITCHELL: Commissioner Clodfelter?

COMMISSIONER CLODFELTER: Yes, good afternoon.

CHAIR MITCHELL: Commissioner Duffley?

COMMISSIONER DUFFLEY: I'm present.

CHAIR MITCHELL: Commissioner Hughes?

COMMISSIONER HUGHES: Here.

CHAIR MITCHELL: Commissioner McKissick?

COMMISSIONER McKISSICK: Present.

CHAIR MITCHELL: And Commissioner Kemerait?

COMMISSIONER KEMERAIT: Present.

CHAIR MITCHELL: I now call to order Docket Number E-2, Sub 1300, which is captioned In the Matter of Duke Energy Progress, LLC's, Request to Initiate Technical Conference Regarding the

Projected Transmission and Distribution Projects to be Included in a Performance-Based Rate-Making Application.

North Carolina General Statute § 62-133.16 authorizes performance-based regulation or PBR for electric public utilities. Pursuant to statutory directive on February 10th, 2022 Commissioner issued an order adopting Commission Rule R1-17B which implements this statute.

On June 8th, 2022 Duke Energy Progress, LLC or DEP filed a letter with Commissioner indicating it's intent to file a Notice of Intent to File General Rate Application that includes performance-based regulation application as authorized under North Carolina General Statute § 62-133.16 with a PBR Application targeted for filing no earlier than October 6, 2022.

DEP also requested pursuant to Rule R1-17B that the Commission initiate a Technical Conference regarding the projected transmission and distribution projects to be included in the PBR Application.

On June 15th, 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, July 25th, 2022 beginning at two o'clock. The purpose of this Technical Conference which is required by Statute is to allow DEP to present information regarding its projected transmission and distribution expenditures.

The Commission's June 15th Order permits interested parties with the opportunity to intervene in the docket and to provide comment on DEP's filing. The Order also permits parties an opportunity to make a presentation today subject to an advanced notice requirement.

Upon the filing of timely motions, the following parties have petitioned to and have been allowed to intervene in this proceeding. The Carolina Industrial Group for Fair Utility Rates II; Carolina Utilities Customer Association; North Carolina Justice Center; North Carolina Housing Coalition; and the Southern Alliance for Clean Energy, to which I'll collectively refer to as NCJC; the North Carolina Sustainable Energy Association; Vote Solar; the National -- Natural Resources Defense Council or the NRDC; and the North Carolina

Electric Membership Corporation filed a Petition to Intervene which was denied, but NCEMC has been allowed limited participation rights and will be allowed to participate in the Technical Conference today, if so willing.

The North Carolina Attorney General's Office has provided notice of its intervention in this proceeding pursuant to North Carolina General Statute § 62-20. And the Public Staff which represents the Using and Consuming Public in matters before the Commission has provided notice of its intent to participate in the Technical Conference today.

On July 15th, 2022, DEP filed its projected transmission and distribution expenditures. In accordance with the Commission's Order issued on June 15th, parties may file written comments on DEP's filing through today, July 25th. That brings us to today.

Today, we're going to hear first from DEP. There will be no cross examination of the DEP witnesses per the terms of the Statute, but Commissioners will be permitted to ask questions of DEP's witnesses. There will be no questions taken on Commission's questions.

Parties who have indicated an intent to present will be allowed no more than 10 minutes each to make such presentation. The Commission will hear from those parties in the following order: The Public Staff, the Attorney General's Office, NCEMC, CIGFUR, NCJC, NCSEA, and Vote Solar.

This Technical conference is being transcribed and the transcription -- and the transcript will be filed in the docket as soon as it's available. Please, as it always the case, do your best today to avoid interference with our court reporter's ability to transcribe the proceeding.

Before we begin, I'd like to ask the parties to identify themselves for purposes of the record. We'll start with DEP.

MR. JEFFRIES: Thank you, Chair Mitchell, Members of the Commission. I'm Jim Jeffries with the Law Firm of McGuireWoods, and I'm here today along with my co-counsel Ms. Melissa Butler from the Law Firm of Troutman Pepper, and we're here on behalf of Duke Energy Progress, LLC. And we've also -- since we're presenting first, if I may, I'd go ahead and introduce our presenters or --

CHAIR MITCHELL: Let's hang on one second. Let me get counsel first, and then I'll come back to you for that. All right. Good afternoon, Mr. Jeffries and Ms. Butler.

MS. LUHR: Nadia Luhr with the Public Staff on behalf of the Using and Consuming Public.

CHAIR MITCHELL: Good afternoon, Ms. Luhr.

MS. CRESS: Good afternoon. Christina Cress with the Law Firm of Bailey & Dixon, here on behalf of CIGFUR II.

CHAIR MITCHELL: Good afternoon, Ms. Cress.

MS. JONES: Taylor Jones on behalf of NCSEA.

CHAIR MITCHELL: Good afternoon, Ms. Jones.

MR. NEAL: Good afternoon, Chair Mitchell, Commissioners. David Neal on behalf of North Carolina Justice Center, North Carolina Housing Coalition, Southern Alliance for Clean Energy, and Natural -- Natural Resources Defense Council joined together with the Justice Center.

CHAIR MITCHELL: Okay. Thank you.

MS. FORCE: Good afternoon. My name is

Margaret Force with the Attorney General's Office representing the Using and Consuming Public.

CHAIR MITCHELL: Good afternoon, Ms. Force.

MR. LEDFORD: Good afternoon. Peter Ledford, also on behalf of NCSEA.

CHAIR MITCHELL: Good afternoon, Mr. Ledford.

MR. DROOZ: And David Drooz representing Vote Solar. Jake Duncan is the staff from Vote Solar who is here today. He is not going to be making oral comments and thus, I'll probably step out early as he will just be an observer.

CHAIR MITCHELL: All right. Thank you, Mr. Drooz.

MR. DODGE: Good afternoon, Chair Mitchell, members of the Commission, I'm Tim Dodge here with North Carolina Electric Membership Corporation. And we do not plan to present any -- make any presentations today.

CHAIR MITCHELL: Good afternoon, Mr. Dodge. Thank you, counsel.

Before we begin, any preliminary matters?

(No response)

We will go ahead and get started. Mr. Jeffries, Ms. Butler, y'all may proceed.

MR. JEFFRIES: Thank you, Chair Mitchell. I'd like to begin by introducing the three presenters for Duke Energy Progress today in the order in which they will present. And from the Commission's right to left, we have Mr. Justin Brown who is the Director of Planning and Regulatory Support for Duke Energy. In the center, we have Mr. Brent Guyton who is the Director of Asset Management for Customer Delivery for Duke Energy. And on the Commission's left, we have Mr. Dan Maley who is the Director of Transmission Compliance Coordination for Duke Energy.

And at this point, we would turn the presentation over to Mr. Brown.

CHAIR MITCHELL: All right. Good afternoon, gentlemen. You may proceed.

MR. BROWN: Good afternoon. Thank you for -- to all the attendees who have joined us today for this Technical Conference. I know your time is valuable. Hopefully, you'll find today's material informative. Again, my name is Justin Brown. I'm Director of Planning and Regulatory Support for Duke

Energy.

I have seated next to me two experts that will be speaking on distribution and transmission investments that will be included in the multiyear rate plan projects. First speaker is Brent Guyton, Director Asset -- excuse me -- Director of Distribution Asset Management. Brent will be followed by Dan Maley, Director of Transmission Compliance and Coordination.

So we'll spend the next few minutes going through and hearing from the experts on discreet and identifiable distribution and transmission-related projects that we expect to file in our multiyear rate plan.

Over the course really of this Technical Conference, we're going to provide an overview of the trends that are impacting our industry and drive our system planning. We're also going to share an overview of the distribution and transmission projects as I mentioned earlier that were included in our pre-conference technical documentation filed back on July 15th. These investments are necessary for the Company to both maintain and advance the grid to support the clean energy transition in North

Carolina.

Additionally our speakers are going to provide specific examples of projects and programs to be included in the multiyear rate period. It's also important to note the presentation today we're going to go over at a high level. It's not going to go through every piece of documentation that we previously filed but hope to give a good overview of those.

Just as a reminder, the documents that we did share in advance on July 15th provide really a detailed description of each planned improvement program or project. The purpose and the description of those projects of the work to be completed, a summary of benefits, the estimated installation cost for both T&D work.

Additionally, we provide a complete list of the planned projects that included the projected in-service dates, the estimated total cost for each individual project along with House Bill 951 policy considerations that are addressed.

And lastly, cost/benefit analyses. We did list cost and benefits of each program and project, and many include a financially-based cost/benefit analysis.

We want to address upfront the federal grants, being the Infrastructure Investment Jobs Act, IIJA. We are actively engaged in ongoing implementation of the federal Infrastructure Investment Jobs Act at the state and federal level. We are participating in requests for information and also having discussions both at the federal level with the Department of Energy, Department of Transportation, as well as the EPA.

For instance, we did file a RFI in early June, June 2nd, along with five other RFI responses that have been submitted, I believe in the open docket, for the Commission already, the IIJA docket. While federal agencies are making progress, they still are in the early phases of the implementation of the federal grants with many activities under development.

While programs are under development, the Company is defining and working through a prioritization process that includes building a framework and operating model with a partnership with an outside firm that we plan to benchmark against our industry peers.

The process will include proactive grant planning. We expect the grant windows to be fairly short, 60 to 90 days when those become available, so we kind of need to have our act together in that approach. Also includes grant writing, submittal, and our execution plans associated with that.
The team is going to carefully review those grants and may apply at both the federal and state level to participate. Our goal is essentially to maximize the impact of those grants for customers in North Carolina.

We look forward to the funding opportunities that are expected to become available in the fourth quarter of this year. But to be clear, we are pursuing the funding opportunities for the benefit of customers and we will ensure that they receive the benefits associated with those grants.

The projects included in our multiyear rate plan and in the materials submitted on July 15th, however, don't include an assumption for any grants received. The projects benefit customers regardless of whether the grant opportunities are made available to the Company. So none of the cost/benefit analysis or the listing of cost and benefits assume any grant awards.

So overall, I believe we would all agree that our grid is in a complex transition. The original design of our grid was somewhat simple and had a few key design assumptions that were -- that were in place. One, that overall generation was firm and dispatchable. The generation generally followed load and always kept the power in balance. Load at the distribution level of the system was treated more as a passive load as opposed that was attached to the transmission system. Power flowed generally in one direction from central generation to the customer, and the grid was designed for reliability.

Overall, the mission of the electric utility has significantly changed over the decades. Our mission used to be to keep the lights on, keep the lights on, and keep the lights on. Now today, we are faced with other considerations. One, we have to be cyber secure. We have to be physically secure. The grid has to be flexible in enabling new technologies that are coming on the grid. We have to be accessible, economical, clean, and sustainable, and upmost we have to be resilient.

Today, those original design assumptions that I mentioned earlier are being challenged. We introduced back in 2019 mega trends or trends that we are looking at that are affecting our grid investments. Those are still present today. One being grid improvement, technologies. Overall, those technologies are continuing to advance at a very high rate. Spending in smart grid IT and analytics overall is expected to grow to $6 billion by 2028. Technological advancements with renewables and DER is growing rapidly, especially here in North Carolina.

As I mentioned earlier, threats to grid infrastructure unfortunately is troublesome. The US and the US ransomware attacks are up by 148 percent over 2020. The impact of weather events is increasing in frequency. North Carolina has been impacted six times by billion dollar storms in some way in 2021, and nine of those billion dollar storms in 2020, the most in North Carolina history.

Concentrated population growth continues to occur in North Carolina. North Carolina has two cities, Charlotte and Raleigh, that are among the top 25 cities growing in the United States.

Customer expectations are continuing to evolve with reliability and affordability being key to their fact topics to us.

And finally, environmental commitments both at the federal, state, and local levels. Fortune 500 companies are seeking places to invest that are -- have carbon reduction and sustainability in mind. Sixty percent of the Fortune 500 companies have carbon goals, much of those located in North Carolina.

And key among that is House Bill 951. Those in the House Bill 951 establish aggressive carbon goals, 70 percent by 2030, and net zero by 2050. The grid improvements proposed are necessary to not only maintain our grid, but also support the clean energy transition and the overall resiliency of our grid in North Carolina.

When we start thinking about the future of the grid, we have to start thinking about it as an enabler. The grid has to be thought of as an enabler for new technologies that safely integrates new grid edge technologies growing the ER technology such as solar, wind, storage, and electric vehicles. To do this, the legacy grid must be upgraded and adapted to accommodate two-way power flow, load shifting, and greater situational awareness.

Traditional forms of grid planning are no longer adequate. The Company has implemented Integrated Systems Operation Planning or ISOP. And those plans leverage more and more data such as the propensity to adopt solar and the purchase of electric vehicles and all that has to be implemented into our planning processes.

Overall, programs will use new processes to implement tailored solutions that essentially is going to build a digital super structure grid that delivers on the energy goals for North Carolina and the requirements for our state.

So when we start thinking about the overall strategy and the future grid, a couple of things bubble up to mind. Three primary adjustments really come to mind. One is overall grid resiliency. We must have a grid that has the ability to withstand and recover from frequent extreme weather events and external hazards. The grid must have -- must be more resilient if we're going to have more and more DER attached to the distribution system overall. Expansions of renewables and DER, the grid must be able to meet that customer demand and be able to accommodate it. If North Carolina has a bold carbon goal, both the distribution and transmission system must be ready for that challenge.

And overall, finally, equitable access to benefits. We must achieve a balanced outcome for all customers across the state to be able to accommodate and be able to leverage the new energy technologies and solutions that are coming. And all this has to be done with an eye towards the most efficient manner of implementation and affordability.

So next I'm going to turn it over to Brent Guyton who will dive into the distribution programs. Brent?

MR. GUYTON: All right. Thank you, Justin. And good afternoon everyone. My name is Brent Guyton. I'm the asset -- or Director of Asset Management for Distribution here in the Carolinas. During my portion of the presentation today, I'm going to cover six areas. One, benefits to customers. Also talk about the four critical grid capabilities needed to achieve the objectives that Justin just touched on.

I'll also overview the work streams and programs that are in our distribution projects. Also the planning approach that we've leveraged to maximize benefits to our customers. I'll also overview a specific MYRP project in our coastal zone in the greater Wilmington area. And then lastly, I'll highlight the 10 program summaries that make up our MYRP project support streams within those.

Before I do that, I want to talk briefly about -- about how we will be delivering the benefits to the customers and establishing and/or strengthening those critical grid capabilities that I'll describe shortly. I'll explain this more as we go along through my part of the presentation, but I want to introduce it here as we get started.

So our projects are planned for a set of geographically clustered substations. Each substation based on its specific needs to achieve those grid capabilities will receive selected distribution improvement programs. It is not a one-size-fits-all. You will see that as I talk about the specific project for the coastal area. And lastly, the work is executed geographically for those clustered substations to maximize, one, resource efficiency; two, minimize the disruption to our customers while we're performing the work, and also deliver the customer benefits across a broad customer area or footprint as we complete that work. All of that infrastructure is uplifted as to the new grid capabilities.

So the benefits from doing this work. First off, reliability. Fewer and shorter outages. I'll describe some of the programs that will support this from self-optimizing grid to targeted underground as well as others.

Resiliency, as Justin talked about, physical and cyber attacks are certainly a threat, but also severe weather impacts. We have specific programs and work to deal with those as well.

Access to renewables and distributed energy resources. Capacity and voltage regulation, two of the work streams that we have in our distribution projects, specifically address the ability for two-way power flow to support DER as well as the voltage regulation and management needed with fluctuations in voltage from intermittency in rooftop solar.

The MYRP projects and the grid capabilities they bring are foundational for future work and support future technologies. Justin talked about the advancements in grid technologies being one of the mega trends. This work is foundational that we can build on going forward.

With enhanced automation and control and also situational awareness, we can operate the grid more efficiently. That's in our control centers. The situational awareness that the operators in those grid -- in the control rooms have allowed them to make better real-time decisions as well as for the automated systems in those control rooms to execute things more effectively and efficiently.

Also with the automation and communication, there are huge amounts of new data that we're generating daily that we can leverage to build additional customer programs and offerings to allow them to have more choice around affordability and control of their energy use.

And equitable access to benefits. I talked about that a moment ago. As we complete our

MYRP projects there across a broad footprint geographic area and uplift those assets and provide the benefits to all the customers in those areas.

The strategy that we're implementing as we go through this is foundation and will support customers in the future. The programs and work that we're doing within MYRP projects truly do make the grid more flexible and adaptable, again, to support two-way power flow and distributed energy resources as an example.

I talked a moment ago about the automation and control technologies in generating huge amounts of data. Not only is that great for our operators in situational awareness, that's also leveraged by our planning engineers for future planning cycles. Leveraging the ISOP tool sets and the subsets of tools underneath integrated system resource planning -- operations planning. Sorry. And as the grid technologies continue to advance, they'll be integrated in new solutions that will be able to address changing customer needs as well.

So I mentioned the critical grid capabilities, and you see the four listed here: Reliability, capacity, automation, and communication, as well as voltage regulation. And let me touch on reliability. There's a historical view and understanding of what reliability means and the impact of outages. That changes in the world as we go forward with distributed energy resources, so let me describe that a little bit.

So in the past, the distribution grid, as Justin described, was built to serve customer load. And when there was an outage, customers, residential as well as commercial/industrial, certainly residential if they had a home-based business, and then commercial/industrial, it was an impact to commerce or loss of revenue in that particular instance. And also if someone now in today's world is a hybrid employee or a completely virtual employee working from home, that outage is now impacting their ability to do their job. That's not been the history that we've had.

And also along with that homeschooling. That has become more the norm, not just from a COVID standpoint, but continuing to grow. That impacts education for our children in the future when we have an outage. It interrupts their learning process.

So now fast forward to the future when we have distributed energy resources that are connected to the distribution grid. Now it is no longer just that traditional impact that I just described. We're impacting the ability of generation to connect and supply power to the grid when we have an outage.

You layer into that electric vehicle charging. There's now an impact of an outage, whether it be fleet electrification at a business or charging a personal vehicle at home, that that outage now has an impact on transportation. That has not been the case in the past from a reliability perspective. So very different lens in which we look at reliability going forward.

Capacity next. It is critical for two-way power flow to build appropriate hosting capacity into the grid, and there's a traditional view of capacity to just serve traditional loads, but now we've got to layer in both an electrical vehicle charging as well as distributed energy resources. And we do that with our MoreCast tools under ISOP to take in and look at that information, and I'll describe that more in a little bit.

Automation and communication. The

self-optimizing grid program is really a cornerstone program that defines resiliency. We're able to have a fault condition on the distribution grid. The system in less than a minute detects where that problem is and automatically reroutes power around that. The ability to take a punch and recover quickly at least in my mind is the definition of resiliency and that program does that.

And last, voltage regulation. We have always had voltage regulation in the distribution grid to follow traditional load moving up and down throughout the day or during the hours of the day. But as we introduce more and more distributed energy resources and you have cloud cover passing over and a generating site can go from maximum generation to minimum generation in seconds or partial seconds, parts of a second, and do that multiple times during the day, we've got to be able to manage that type of fluctuation and voltage on the distribution grid. That requires new capabilities in voltage regulation management.

So that's a lot. Four broad categories of grid capabilities in my description. What I'd like to share is really the kind of analogy of how I see all this coming together. So I want you to think about the vehicle that maybe you learned to drive on or you rode in with your grandparents as you were growing up, and think about the technology that was in that vehicle versus the one that you probably used to commute to this meeting today or maybe sitting at home in your garage now.

When I think about reliability or longevity, we used to talk about tune-ups for old cars. You don't hear that term anymore. The cycles of maintenance are much more extended, last longer without having to do any maintenance on those vehicles.

Efficiency, likely the vehicles of today, at least for gasoline or diesel engine, they're smaller than the historical vehicles and yet much more powerful and much more efficient based on where they are today.

When I think about automation, the first example of automation I can think of in vehicles, it was an automatic transmission versus a manual or a standard shift transmission. We now have things such as climate-control automation, Bluetooth connections to your phone; self-parking vehicles is now part of the automation we see in vehicles today.

Control or advances in control, same thing. I think of cruise control as one of the earliest examples I can think of for control in a vehicle.

We now have antilock brakes as well as radar on a vehicle where if you set your cruise control and you begin to encroach on the vehicle in front of you, will automatically slow your vehicle down and adjust your speed to maintain a safe following distance. As that vehicle moves out of the way or you change lanes, it will automatically move you back up to your speed while maintaining that distance.

And lastly, situational awareness. In the older vehicles you may have had a rearview mirror or side-view mirrors, and now they're surrounded with cameras, again, radar on the front of vehicle to look at closing distance on other vehicles.

Think about what you have inside the vehicle with the dash. A simple gauge cluster potentially with a speedometer in the past, and now there's a touchscreen driver information center with multiple screens that you can advance to to make any changes in the vehicles.

That's the type of transition that I see in the advancements of technology that's necessary on the distribution grid, and we're on that pathway now. But that gives a broader view, at least in my mind, of how that moves and one that hopefully most of us can relate to. So we're going to talk about the programs themselves that make up our projects.

You'll see on the left-hand side of this graph the projected spend over the three rate years, October '23 through the end of September of '26, total of $1.8 billion projected for the work in the distribution projects. There's three categories you see with substation and line making up the majority of those, but also hazard tree removal as well as retail and system capacity.

You'll see those listed again in the center of the table there. And then also there's details further over to the right.

One thing I want to point out and speak to is that within substation and line, you see capacity. It's the very first detail that you see listed there at the top. You'll also see hazard tree removal one up from the bottom in the substation and line category.

But you'll also see retail and system capacity listed separately and also hazard tree removal. In both cases that's the same work. It's where it's happening geographically that's the difference for those. The capacity work is not only serving traditional loads, but also additional capacity for electric vehicles and distributed energy resources. Within substation and line, it is geographically located with another critical mass of work that could all be executed together as a large project. Whereas the standalone capacity is identified thermal overloads for the three-year rate periods that we need to be addressed, but they are not physically adjacent to other critical work that we can execute as a larger project.

The same thing for hazard tree removal. It's the same work both in the substation and line areas as well as the standalone. As part of our integrated resource -- sorry -- integrated vegetation management plans, we have maintenance of our right of ways, so the prescribed right of ways around our distribution lines that we maintain and remove vegetation within the right-of-way, hazard tree removal is focused on threats from outside the right-of-way. Dead, diseased, dying, or otherwise structurally unsound trees that can fall into the right of way and damage and contact our facilities.

So again, both of those are needed. We've identified trees that our outside and away from the other projects as well as some that are geographically located but we can execute at one point.

The 10 programs that are part of the substation and line, there are short descriptions here on the page, I think, that are very descriptive.

Again, capacity is about line capacity both traditional DER as well as EV.

Self-optimizing grid or the self-thinking grid, you may have heard that term, is about detecting faults and automatically rerouting power to restore as many customers as possible.

Voltage regulation. I describe that as one of the critical grid capabilities and now -- and we also are describing a program that directly adds that capability in.

Hardening and resiliency. Justin touched on that as one of the key areas for the grid to strengthen and avoid threats.

Specifically, there are three areas I'll talk about as we go into the program summaries and these are focused on more physical threats, both severe weather as well as other impacts to the grid.

Equipment -- I'm sorry. Distribution automation. Adding automated restoration capabilities in certain portions of our lines. Also equipment retrofit. This is focused on three different asset classes; transformers, arrestor stations, and riser poles. And riser poles are where our facilities transition from overhead to underground. That last pole where the conductors transition to underground is referred to as a riser pole. There's some equipment modifications that we can make on those to make those more reliable.

Long duration interruption. This is looking at areas of our system where the facilities are hard to access. They typically are more remote customers geographically isolated where we may serve entire communities or groups of customers and we have higher than normal duration outages when they do have an event. And I'll talk more about that as well.

Targeted undergrounding is a data-driven approach to look more at the laterals of our system and where we have unusually high frequency of outages and potentially placing those underground, and also relocating from typically rear lot to front lot as well.

I talked about hazard tree removal and I'll describe that more as we get to the program summary.

And then lastly, infrastructure integrity. This is about looking at the foundation of the grid on which we'll build all the other work that's there and make sure everything is intact while we're in that area executing those larger projects. Make sure everything is where it needs to be to support the ongoing needs of our customers from that.

All right. I want to talk about how we actually plan and build out and assemble the MYRP projects.

Overarching this, and I'll go ahead and say this here, the integrated systems and operation planning tool sets are a key part of this, especially for our distribution planning engineers with the advance distribution planning tool sets as well as the MoreCast load data that's leveraged to look at capacity needs going forward.

I'm going to start on the graphic and really from kind of the lower left, that seven o'clock position and work my around clockwise as we get through this.

We do at the -- so planning engineers, they are assigned a geographic area. There's a set of substations and circuits that they have personal responsibility for to do all the analysis and load flows and calculations that are necessary here. They do that at a circuit level, but they're also looking broader across the area at the roll-up to substations in their areas also.

The first thing to do is leverage the MoreCast dataset. That's a 10-year hourly view within our ISOP tool sets providing load information for the planners to analyze. It not only looks at traditional loads, but also electric vehicle impacts as well as distributed energy resource impacts as well. And all that is included in that capacity analysis.

They're also looking at the other critical grid capabilities I mentioned; reliability, voltage regulation, as well as automation and communication. Once they've identified that current state and where there are potential gaps in the capabilities for those -- those individual circuits, those are then looked at across those -- all 10 of those programs to layer in an approach to look at what the benefits are that could be delivered to customers and how we could actually raise the capabilities for those -- for those circuits.

That then is really the balanced circuit approach; the outcome of that looking at what's needed for individual circuits. And again, it's not a one-size-fits-all. It's based on the analysis they've done of what the needs are for those individual circuits.

This is where you see in the middle of the graphic, you see project development and also asset management listed, the duties I've spoken to so far as within asset management. But this next step is where project development gets involved, so they collect and intake all that information from the planning engineers across the system and start to do a system-level analysis. What is all the work that is necessary across the system within this particular MYRP period?

That then is iterated against things such as any potential labor constraints, any material issues that we may know about, as well as annual budgets. That is an iterative process and then developing -- these are the annual plans to be developed into MYRP projects.

That then begins the process of sequencing that work at high level schedules for the individual substations, and then those geographically clustered stations that is all aggregated together to form the MYRP projects for that.

One thing I want to mention is I've talked about MoreCast being a 10-year hourly forecast to look out over that 10-year horizon. That 10-year horizon is necessary to truly give transmission and generation a view of what impacts distribution will have on the overall system and how they incorporate that into the Integrated Resource Plan.

The planning engineers while they have that 10-year view, they're not looking to scope projects and solve problems that are in years six through 10. They are focused on years three through five. What are the near-term thermal issues, automation capabilities, voltage regulation needs, as well as reliability in that three-to-five year window? That's the work that needs to be executed now and plan now for the next three years. We will then come back and analyze again in the future and continue that iteration and pick up those out-of-year projects as appropriate in the future. So again, a proper planning horizon, not over building, but look at near-term needs for the grid.

So we'll take a look at a project. This is a fairly busy slide, but before I move over here to the table, I want to talk about what's in the box on the left. And I talked about this earlier, so I want to circle back to some of my earlier comments.

The project-based approach that we leverage. Again, we analyze at the circuit level, roll that up into plans for Duke geographically set of substation -- or geographically located substations. We select only the improvement programs that are needed. It's not a one-size-fits-all. What are the things needed for those circuits? And again, only in that three-to-five year window.

And lastly, the improvement programs are selected. Those are then rolled into MYRP projects for -- to be executed and also at that geographically clustered level.

And the reasons for that is to maximize resource efficiency. We move and mobilize into an area, do all the work that's necessary, and then demobilize and move to the next area. That minimizes customer disruptions. Yes, we're still there working, but we're in there and out of there as efficiently as we can. And when we leave, the benefits to the customers are all there. Everything that we were going to do on behalf of the customer is complete as we roll out of that area and move to the next area.

I'll share another analogy I think that helps describe this a little better. Think about a house remodel. And I'm not talking about one individual room. I'm talking about a whole house type of remodel. The first thing you'll do is think about what the needs are that you have for your house. There may be things that are end-of-life assets. You may want to improve the efficiency of your home. Maybe it's an older home. Replace windows, doors, insulation, new HVAC system. Maybe the plumbing is an older vintage of metal pipes as opposed to modern plastic pipes.

There may be things that you need from a home automation standpoint, upgrades to appliances, et cetera. Possibly a new roof. You may have to start taking care of aging parents. You may have to create an aging-in-place benefits and areas in your home to be able to accommodate them.

So once you've identified all that, there's a couple of ways you could execute that house remodel. One, you can do a lot of small individual projects. It likely takes a long time. Future projects as you do the smaller ones may end up impacting a project you just finished and there may -- it may cause you to undo something you just did to complete the next little project. It certainly seems less efficient, and the disruption to you and your family as you're going through this remodel seems to go on forever. There's no end in sight what's going there.

And even as you complete each of the individual projects, it's really hard to appreciate the benefit that you brought by completing that one project, because there's so much other things that still aren't where you need them to be providing those benefits.

Contrast that with all the same needs that you have for your home remodel, but you aggregate all that into an overall project for the entire remodel of all -- of your entire home. You still identify all those things you need to change or upgrade and things you need, but you likely hire a general contractor and other professionals to come in and look this over. Aggregate all that into one project, sequence the trades that come in, and take apart to do the individual parts and work streams of that. That minimizes any rework. It is still disruptive and inconvenient for your family, but it has an end. And when that general contractor walks out the door for the last time, you and your family enjoy all the benefits and things you were trying to accomplish with the house remodel. It's one and done as opposed to seemingly go on forever.

And just like the remodel that I may do versus Justin, each one is different, and you'll see that for our substations projects where they're individualized for those substations and circuits within the MYRP projects.

We'll take a look now at the sample project there. This is actually in our coastal zone and this is area 282 which is the greater Wilmington area. You'll see that it's made up of 21 geographically clustered substations, and their names are listed down the left-hand side of this table. You'll see the ones at the bottom have the word Wilmington in them. Again, that's the greater Wilmington area including outlying areas as well.

Across the top in the blue headers, you'll recognize those 10 categories are column headers as the programs that I described briefly earlier, and we'll go into more detail with the program summaries.

I put a box around one of the substations there in the middle, Murraysville. And you'll notice that out of the 10 programs there are only six selected for that substation, and the reason for that is there are not any capacity needs or self-optimizing grid needs in the next three to five years for Murraysville substation. That work is either already been done previously or it doesn't show up in our cycle planning until after year five.

So it's in those out years that we'll catch in a future cycle from that perspective.

You'll see other variability across the other substations listed within this MYRP project. And again, the same application applies. The analysis was done. The work is not needed at this time. And where you do see the checkmark, there is a roll-up of that type of activity on that substation.

I'll reiterate again here what I said earlier, that really we're looking for these projects in that three-to-five year timeframe. What are the critical grid capabilities needed then, not out to as far as we can see with the MoreCast tool in the 10 years. This is focused in on the front half of that planning horizon.

One last comment I'll make while I'm on this slide. The maturity of the estimates that we have in our file materials for this Technical Conference these estimates are all as of early June. We certainly are facing other economic uncertainties. And as we refine our estimates through our process, we'll make sure through the appropriate vehicle to make sure the Commission and all stakeholders are informed of what those changes are if some of these do change going forward.

All right. We'll now move into the program summaries. And as I talk about each one of these programs, there's two slides for each program. The first one will be a program overview like you see on the screen here for capacity. There will be a second slide for each one that focuses on the benefits of doing that particular work or work stream.

For -- also you'll see -- well, let me talk about this first, then I'll touch it before I leave the slide. Capacity upgrades are not new. But as I described earlier, the new layers and areas of capacity that we've got to look at are electric vehicle adoption as well as distributed energy resources and the two-way power flow necessary to accommodate those. That is all part of, as I mentioned a couple of times earlier, part of the MoreCast data that's leveraged for the capacity analysis for each of the circuits that we look at.

There's also the automated distribution planning tool set which is part of ISOP. That includes automated solutioning which allows us to analyze, or a planner to analyze, not only at the circuit level for the individual thermal overloads that are identified, but also in that area adjacent circuits and substations leveraging that MoreCast peak data on how to best alleviate that thermal overload. And that may include balancing load transfers to other -- permanent load transfers to other circuits, conductor and device upgrades which are more traditional capacity implementation, as well as nontraditional solutions also.

You'll see -- in the program description box you'll see two different headers; retail capacity and system capacity. And I want to take a moment to explain what the difference is for -- or difference between those are.

They're both necessary for the same reasons, which is support traditional loads as well as DER and electric vehicles. The retail capacity work refers to upgrades or work done on our transmission to distribution substations. We call those retail stations, because they are the substations that serve distribution's retail customers as opposed to transmission's wholesale customers that they serve from other types of substations.

The work that would be included for retail substations would include transformer upgrades or new transformers within the substation. It may include breaker additions if a new distribution circuit is needed outside of the substation. And it could even be a new substation in an area that's growing quickly and serving that load center from other stations that exist in that area is not practical from that perspective. So think of retail capacity work as work inside the substation fence.

System capacity is really the opposite of that. It is work outside the substation fence on the distribution lines, again, serving the same types of capacity needs. And this would include upgrades to wires and/or equipment as well as new circuits to serve growing load in certain areas. So retail capacity is inside the fence. System capacity is outside the substation fence.

In each one of the program overview slides, you'll see estimated construction on the right. Estimated construction timelines, estimated in-service dates, as well as projected costs. And in the bottom half of that box, you'll see critical grid capabilities and -- sorry -- critical grid capabilities enabled, and that refers back to the four that I talked about earlier: Capacity, reliability, voltage regulation, and automation and communication. And then lastly in the bottom, House Bill 951 policy considerations that are also addressed.

I won't spend much time on those. I'll focus on what the program is as well as -- as well as the benefits for each of those.

So let's talk about the benefits for capacity. Reliability and resiliency and expanding the solar renewables. Without doing proper capacity upgrades, we risk failures of overloaded conductors and equipment at peak times. Therefore, building in the necessary capacity in advance at the right time reduces potential outages from those conditions.

Capacity improvements also help from a resiliency standpoint. While it certainly can be leveraged for the traditional means, it also provides alternate paths for switching and other redundancy when we have impacts to the grid.

And I've mentioned a couple of times already capacity enables two-way power flow, which thus supports additional renewable energy resources as we transform the grid to more carbon free sources.

So self-optimizing grid. I mentioned earlier this is a cornerstone program for distribution and addresses actually multiple critical grid capabilities. If you go ahead and look to the lower right, you'll see that three of the four are addressed by this singular program, and that's the reason I call it a cornerstone program for distribution. It addresses not only reliability, but also capacity and also automation and communication as well.

As we're scoping and identifying self-optimizing grid needs, this is an area also that specifically the planning engineers leveraged the ISOP tool sets such as advanced distribution planning, and there's even a sought automation portion of those ADP tool sets that also provides suggested automated placement of those switching devices along the circuits that they're studying. The planners still review that for -- to see whether that makes sense or not, but they do -- are presented with automated solutions based on the criteria for self-optimizing grid.

There's three major components to self-optimizing grid. You see those listed in the program description. First off, capacity. So you may be thinking okay, we just talked about capacity and you're talking about capacity again, so let me explain the difference between the two.

The previous capacity that I spoke of is going to serve what I'm going to call native load for a particular circuit. So in that -- in the normal situation, this is all the load that that circuit has to serve traditional EVs as well as DERs.

Self-optimizing grid. The purpose of that is to have two circuits or more that provide backup capability to adjacent circuits. So it's not only do I -- does circuit A have to serve all of its traditional load. If circuit B has a problem, circuit A needs to pick up some of those customers and pick up some of that load. So that's additional capacity for what I'll call emergent conditions or impacts to the grid, not just that native load that's on the circuits.

The same analysis occurs and the planning engineers are actually looking at both of those at the same time and one that's not doing multiple work. It's the same work. And it either will solve both problems or they're trying to solve one. But they look at that together for both so that we're doing it one time and one time only.

Connectivity. I talked about the two circuits needing to back each other up to be able to form that. They have to be physically connected with a strong tie to transfer load back and forth in outage or fault conditions.

And lastly, the automation and communication. This is about applying those intelligent switches out on the grid, also the automation software back in our control centers that provides command and control usually in less than a minute when it detects a fault situation to restore as many customers as possible for that.

There is a schematic in the middle of the diagram or middle of the slide at the bottom. I think it's much easier to see in the detailed program summary. Let me describe what that is. That's actually a schematic for an actual self-optimizing grid in our DEP North Carolina territory. This one is actually in -- just adjacent to the Asheville airport, so it's in the western part of DEP's territory.

What you'll see is, toward the top of that picture there's two circuits that originate from one substation. The one that goes down and to the left is the Airport Road circuit and serves the Asheville airport and surrounding areas. There's also one that goes down and to the right and that serves the Fletcher area to the east of the airport.

What this is indicating, you'll also see several boxes or squares. Some are -- a couple of green, some are red, and some are red crosshatched. Those represent the automated switches that have now been placed on those circuits as part of the self-optimizing grid.

Also you'll see what looks like a cloud and a lightening bolt kind of in the upper left toward the center. That's indicating between those two green boxes that we actually have a fault condition on the circuit and in less than a minute the system has determined where that fault is. It's opened those two green switches - green means open for us - and then closed all the other appropriate switches to restore as many customers as possible, all in less than a minute without human intervention.

The operators in the control room are aware of what's happening and can take additional steps as necessary, but that's what the self-optimizing grid does.

And one last piece of information here. So within -- between those two green switches that you see where the fault is, there's 488 customers that are -- that have a sustained outage until a crew can respond, find the problem, and fix it. Before self-optimizing grid was placed on these two circuits, that same fault event would've resulted in 2,691 customers having a sustained outage. So from 2,691 customers with a sustained outage to 488. That's what self-optimizing grid can do for us and for our customers.

So one other analogy I'll share here is if you think about the grid of the past, and Justin had a slide that talked about this, think about a bicycle wheel. You've got the hub and you got spokes going out to the wheel. That's a very simplified representation of what the historical distribution grid looked like. You can think of the hub as being centralized generation or a substation, and then the circuits go out to serve the traditional loads.

Now, think about a spider web. Spider web still has a center. It still has those radial spokes that go out to attach to the doorframe or the tree limb or wherever the spider built it. But there's also dozens if not hundreds of connections between each of those spokes all the way around the grid. That's the type of inter-connectivity that's necessary in the future to be able to support distributed energy resources. Multiple pathways to move power and restore power if needed across the distribution grid.

Let's talk about -- I've talked about benefits, but we'll go to the benefits page for self-optimizing grid. Certainly, reliability and resiliency in this case go hand in hand. One, we're preventing sustained outages from a huge number of customers in that example. But also, the system itself is able to take a punch and respond quickly to a fault condition and recover automatically as many customers as possible from a resiliency standpoint.

I mentioned again -- or earlier that it supports solar renewables because we are building capacity for emergency backup. That same capacity can be used to move distributor energy resource generation around the distribution grid.

And lastly, at the bottom you see the benefit/cost ratio of 5.5 for the self-optimizing grid work.

So voltage regulation and management. This is specifically work to address the grid capability that I described earlier of managing those fluctuations. And as I said earlier, voltage regulation is not new, but the impact to DERs, as the penetration becomes higher and higher, is to mitigate the voltage fluctuations that occur from generation moving from max to min as clouds pass over.

There's really three that, we say three levels to the program. I'll say three different types of work we do. The first is additional voltage regulators installed on the grid to be able to manage those fluctuations. But also for existing voltage regulators, we installed new controls that are capable of determining two-way power flow. Current controls are built to look at the substation as the stiff source of power and only regulating voltage down stream of that. These new regulators or the new controls have to be able to look in both directions and properly mitigate voltage fluctuations.

Capacitors. Capacitors are not new on the distribution grid. That supports or provides reactive power support and voltage regulation reactive power support work hand in hand to properly manage voltage levels on the distribution grid for that. But there will be additional capacitor needs as we move into higher and higher penetrations of DER.

The new part of this is actually power electronics. Power electronic devices have the ability to both manage and control voltage as well as provide reactive power support and do that almost instantaneously. That is the new capabilities that are needed in the future.

One will have those rapid fluctuations from DERs, but also think about traditional regulators and capacitors were meant to follow load throughout the day, raise voltage and VAR support, and as the load came down in the evenings move back the other direction.

With intermittency, those maybe have the potential to chase voltage fluctuations during the day and always be following trying to chase that.

The power electronics can damp out those rapid changes and manage those where truly the regulators and capacitors perform the more traditional function of increases as load moves up and down during the day from that perspective.

One other way to think about that is think of capacitors and regulators as the course, voltage, and reactive power adjustments and the power electronics give you that not only fine adjustment, but also instantaneous adjustment to deal with those fluctuations.

So let's talk about the benefits for voltage regulation. And this is really about maintaining proper voltage levels. We're required to maintain voltage as part of our obligation to serve within certain prescribed limits. This allows us to maintain and continue to do that even with the intermittency and voltage fluctuations introduced by distributed energy resources.

That improves the voltage experience for customers and maintains what they experience today. By doing and applying -- doing this work, we're able to support additional DER penetration on the grid as well as what is there today.

And then by properly managing voltage, if customers have any concerns about the ability of us to deal with roving electric vehicles or DERs, we'll have this capability there ready for those customers. That will not be part of their concern as they choose to make those kind of choices in the future. And certainly, this helps with two-way power flow of properly managing voltage in that case to prepare the grid for a lower carbon future.

So hardening and resiliency. There are three different areas that I talk about in this space. The first of these is laterals. And let me make sure and draw a distinction between laterals and the backbone on the distribution grid.

I think you can think of transmission, I think Dan would agree with this, as the interstate highway system is what transmission is. There are super highways and others, but all call them limited access highways.

When you think of the distribution grid, think of four lane or urban highways or maybe they're even rural highways, but they're not limited access, and then all the side roads that turn off -- that go off of those main roads. The laterals -- when you hear me say laterals or tap lines, I'm talking about the side roads. It's the smaller portions of the distribution grid where most of our customers live, but then we'll have also programs that work on the backbone. SOG is an example of one that is focused on the backbone. This particular program, the reason I draw that distinction is it's focused on the laterals.

One of the things to keep in mind, if you remember my for-reliability-description early on of not just traditional impacts of reliability but now we're impacting an outage, impacts generation as well as electric vehicle charging. Most of our customers live on and are connected to the grid on the laterals. Many customers are on the backbones, but the vast majority are connected via the laterals. So the lateral reliability takes on a new dimension as we move forward with the grid of the future for that.

This is a data-driven approach looking at outage history and very specific cause codes for the outages on those laterals, as well as the review of the physical condition of the wire typically looking for damage or potentially multiple splices when indicating that the line has failed before and been spliced back together.

What we most commonly find with this program that needs to be addressed is an older vintage steel core wire. It was a high strength wire, an older, vintage, of material gave us high strength, but over time that steel core that provided the strength presents a corrosion risk. And as that corrosion risk increases, there's potential failure in those particular cases.

Our standard -- modern standard now is an all-aluminum high-strength alloy that we deploy in new construction. These laterals would simply be upgraded to our current standards with that high-strength all-aluminum alloy for that.

One other comment I'll make here is as I go through the rest of these program summaries, early on, we had programs that were focused on capacity, focused on voltage regulation and then, of course, self-optimizing grid covered three of the four; the rest of these will all focus on reliability. And the reason for that is what I've described, the impacts of an outage now is -- are in the -- now and in the future is also on generation as well as electric vehicles.

So the benefits of hardening and resiliency for laterals, reliability and resiliency, eliminating the risk of outages increase the reliability. Improve resiliency. A modern high-strength conductor provides the ability to withstand limbs falling on others that an older conductor with a corrosion risk may not support as easily. And then upgrading historically outage-prone assets lessens the quantity and duration of outages, so overall system resiliency and reliability increases.

Any time we avoid an outage that bends the restoration costs curved down for all customers. And then the reliable and resilient grid is certainly necessary for distributed energy resources in the future.

And lastly, the benefit cost ratio you see for this of 9.4.

So, the second part of hardening and resiliency is public interference. And public interference is a utility term that we use to indicate any time a non-utility worker has impacted the facilities, whether it be just damage or causing an outage. It may be a contractor digging that hits an underground cable. In this particular case, what we're focused on is vehicle accidents where we have cars hit poles.

For any of you that watch the news, whether you live in it or just watch the news in one of our metropolitan areas - Raleigh, Charlotte, Greensboro, High Point, and others - likely several times a week during the morning news, either the traffic reporter or some live on-camera reporter is reporting on a vehicle accident that's damaged Duke Energy's facilities, and typically it's broken a pole. There's a large outage in the area and traffic is probably impacted for several hours as they attempt to make repairs in that case. So not only is there the impact to the customers that are actually experiencing the outage, there's societal impacts impacting commerce from transportation and traffic rerouting and other things of that nature.

So this particular program, we're focused on those areas where we see with our data now that we've got repeat hits in certain areas. And also, this is focused only on our three-phase, so the most impactful types of events where we have a car hit pole.

The solution set would include potentially design change, a relocation of the existing facilities or potentially undergrounding to remove them from the line of fire from particular repeat vehicle accidents in those particular areas.

So we'll talk about the benefits. And one of the first things that I'll point out is the benefit cost ratio is less than one, and let me talk about that.

So the benefits are reducing or improving reliability and resiliency by relocating facilities, avoiding an event, and making the system more -- ability to withstand any kinds of impact. But with the benefit cost ratio, we believe this is prudent utility practice. We've got data that now shows and we can track where vehicle accidents occur on our backbone systems. And there's -- also, as I mentioned besides the pure reliability benefits that go into the cost-benefit ratio, there's the societal benefits and impacts on commerce, and just traffic in general in those particular areas where this occurs frequently in those areas.

You'll also notice that overall -- compared to the overall MYRP projects that we're proposing, this is less than $16 million, so very targeted to areas that we see areas for Improvement in that particular space.

So distribution hardening and resiliency: Storm, so the last of the hardening and resiliency. This is also a data driven looking at outage history but very specific storm cost codes and also a geographic analysis looking at more of our coastal areas and mountains to look at potential tropical impacts, as well as winter-type weather, icing and others.

There's a lot of information there in the program description, but at the heart of it, it talks about Grade B construction and NESC 250B-D loading. What that -- the simple boil-down to that is what that analysis results in is in these areas where we have propensity for higher winds and heavier ice loads is larger and stronger poles, shorter spans between those poles and additional guy wiring to support those structures in the event of high winds and ice loading where we've seen it happen, repeat again and again in those areas.

So moving onto the benefits. Again, reliability and resiliency. The grid itself being stronger, able to withstand higher winds and heavier ice loading is the definition of resiliency. Also, by reducing the risk of outages caused by those potential severe weather events we're improving reliability.

Outage cost avoidance. Any outage that we prevent bends the cost curve down for all customers from a restoration perspective. And certainly more reliable grid supports additional DER and EV adoption. And you see the benefit cost ratio of 8.7 for this work.

Distribution Automation. This is an existing program. It modernizes traditional protective devices on our laterals. So again, this is a program focused on the laterals, not the backbone of our distribution circuit, and this is accomplished by replacing a traditional single use fuse with an intelligent electronic device or an automated lateral device. You see an acronym there in the middle. It's really a modern recloser for a single phase device and fits in the same location that a traditional fuse would.

I'll share another analogy here. If you think about -- I mentioned your grandparents car and what that -- the modern technologies that it had or didn't have. Think about an older home with a fuse box. Not a breaker panel but a fuse box. And if you lived in a house like that, my grandparents' house had one. When the lights went out in the bathroom or the kitchen, somebody had to go to the back porch where the fuse box was, open the panel, look for the blown fuse. There was probably a box or two or three boxes of different size fuses sitting on the shelf. You unscrewed the other one just like unscrewing a lightbulb. Screw the new one in and the lights came back on, if the fault or the problem was temporary.

What I also make sure that I want to say here is that most faults on overhead systems for distribution are temporary faults. A couple of examples: It may be a limb that's falling from a tree, temporarily brushes the line, and continues to fall to the ground, or it may be an incidental animal contact. Those also tend to be temporary faults on the system.

The challenge with that traditional fuse, just like the fuse in your grandparents' fuse box, is if the fault is -- magnitude is high enough or it's just long enough, potentially the fuse does what it's supposed to do: It opens up and protects the lines or the circuit from further damage. But it's a temporary fault, so we now have customers that are experiencing sustained outages based on temporary faults.

With these automated lateral devices, they can actually reset themselves. So they will sense the temporary fault. They may open up and deenergize the line, but in a couple of seconds they will close back in. And if it truly is a temporary fault, the customer saw a blink, but nobody has a sustained outage at this case. So, that's the value of these devices. You can kind of think about your modern breaker panel that you have in houses of today, but you still have to go out to that breaker panel and turn it off and turn it back on to reset it. These devices do that on their own. There's no human intervention needed.

If it is a permanent fault, it will operate and end up staying open and there will be a sustained outage as it should be for a permanent fault. But temporary faults no longer in this case where these devices are deployed cause sustained outages.

And again, we talked about reliability being one of those critical key grid capabilities based on generation as well as electric vehicle charge. The benefits of reliability and resiliency again and you see the cost-benefit ratio for this work of 5.1.

Equipment retrofit. This is also an existing program. It targets equipment prone to outages caused really by three things: Lightning, overvoltage, clearance issues or animal -- and/or animal interference. And it really upgrades those assets to our modern design, construction and material standards. The types of equipment, I mentioned this earlier that we focus on with this program, are transformers, arrester locations, and riser poles. And remember, riser poles are where our system transitions from overhead to underground. It's that last pole where that transition occurs, is known as a riser pole.

The work that we do in these locations is similar in each of the three examples or asset classes. We install, number one, local fuses. That way, if there is a problem at that device, only the customer served by that particular asset experience an outage. Without those local fuses, the outage is further out to the next protected device and customers that don't need to be out, based on that failure, experience an outage right now.

We also install animal guards and covered lead wires that mitigates animal interference. And also specifically for lightning arresters, whether they are on a transformer or an arrester station, we replace older vintage porcelain lightning arresters with modern polymer lightning arresters that increases the insulation levels on the distribution lines at those locations.

And lastly, we replace conductive metal brackets with non-conductive, typically fiberglass brackets. Again, that helps with clearance issues as well, animal interference, and other clearance issues on those locations.

Benefits, like the others, improve reliability and resiliency reducing the number of outages. With those improvements of construction and design standards and materials that we made at those locations, they are able to mitigate animal interference and withstand those contacts without causing an outage. Outage cost avoidance from fewer outages, again for all customers, bends the restoration cost curve down. Certainly improved customer experience for those customers that are served by these assets as they're brought up to modern standards. And lastly, you see the benefit cost ratio for this work of 3.0.

Moving on to long duration interruption. This is another existing program, and it relocates segments of our overhead circuits. This is focused on the backbones as opposed to laterals. So this one is again focused on the backbones.

And moving those facilities from hard-to-access areas to more truck accessible areas. That certainly reduces outage restoration time and also allows for ease of maintenance to reduce future outage risk when they're easily accessible by mechanized equipment.

The targets that show up in this program are typically -- number one, they're typically radial distribution lines that serve either large groups of customers or maybe entire communities that tend to be geographically isolated. And it doesn't make sense for us, from a cost-benefit ratio, to build an alternate feed from another direction because they're isolated geographically. So, the best thing we can do at this time is move those lines from inaccessible areas such as off road, swamps, mountain gorges or other extreme terrain. And they also have typically higher than average outage durations because it's radial and then the lines are inaccessible. It takes our crews longer to respond, find the problem, and make repairs.

Then you layer on top of that extreme weather, if these were in a swampy area and we've got a tropical-type of severe weather event, that just exacerbates accessibility, and til we get to that equipment. Same thing in the mountains. If you're in a mountain gorge or an extreme terrain in the mountains and you have an ice and snow event, again because they are not track accessible, extremely difficult to get to. And the solution for these is really to move those to road right-of-way or truck accessible areas.

The benefits, similar here, reducing those outage risks. So reliability, resiliency, bending down the outage cost curve by reducing the number of outages that occur. And also more shorter outage durations in those extreme events or when they do have one because it is truck accessible.

This not only bends the cost curve down for outages that don't occur, but the cost of restoring in those extreme terrain areas typically is much more manpower than traditional, very specialized equipment to get in there, and we can do that -- if we move those to road right-of-way we can leverage our standard equipment and access from the roadway and repair much quicker in those cases.

You also see the benefit cost ratio of 14.0 for this particular body of work.

Targeted underground. Another existing program. This one is also data driven. This one focuses on our laterals, so back to the lateral parts of our system. Strategically identifies in undergrounds the most outage-prone overhead line segments. This reduces not only the outages for those customers served by those line segments, but once we've undergrounded those, they typically are in heavily vegetated areas in rear lot. It eliminates that vegetation management cost in the future when those lines are placed underground.

The attributes that typically show up for these targets of unusually high outage frequency. The location of the lines currently is typically rear lot built behind houses and inaccessible to mechanized equipment. And typically over the years those have become heavily vegetated even if they weren't when the lines were originally built. And the solution for these is to move those to the road right-of-way or front lot and also underground those lines as well.

Also, for this program, no surprise, reliability and resiliency are key by putting lines underground. Certainly less susceptibility to weather impacts at least in major events and normal storms. We've also eliminated, as I said earlier, that vegetation management cost and also the restoration cost. Those lines are much easier to access and restore being moved to the front lot line. Again, we don't have non-mechanized outage restoration happening behind homes. And again, the laterals are where the majority of the EVs and distributed energy resources will show up as we move into the future. So that lateral reliability is even more important. And lastly, you see a benefit cost ratio of 7.0 for this work.

So hazard tree removal. And then I'll finish with infrastructure integrity. Hazard tree removal. And I described this earlier, but I want to reiterate this is part of our integrated vegetation management program. One portion is focused on vegetation management within our prescribed rights-of-way. An example may be a 30-foot right-of-way for distribution lines so our lines are in the center and we maintain 15-feet either side of those facilities. This work is not focused inside the right-of-way. It is very specifically and limited to the outside the right-of-way. And what our specialists are looking for is dead, diseased, dying or otherwise structurally unsound trees that if they fail they fall toward the distribution lines and cause impacts to our system. And I'll also say vegetation within the rights-of-way typically is smaller vegetation. It's limbs falling, et cetera. Many times, it doesn't actually damage our facilities, it just causes an outage, but at most it typically would just break the wire.

You have a tree falling from outside the right-of-way, it is not only going to take the wire down, it likely is breaking a pole or multiple poles that now have to be replaced so we have infrastructure replacement to do before we can even begin restoration in those cases. And to talk about the impact of trees from falling outside the right-of-way: for DEP North Carolina, the last five years, 2017 through 2021, every single year more than 50 percent of our vegetation outages were from trees falling from outside the right-of-way in that case. So heavily impactful from that. And again, this is all outside of our right-of-way.

The way we accomplish this work, a Duke Energy representative specializing in vegetation practices leverages an industry best practices to identify those dead, diseased, or dying, or structurally unsound trees. If they do discover an extreme risk to infrastructure that is in imminent failure, they will assign that to a vegetation supplier to immediately take that tree down, but the vast majority will result in a list of hazard trees in locations presented to one of our vegetation suppliers. They make contacts with the customer, explain the work, receive consent, and then schedule to take those trees down on a particular schedule.

And the benefits for this, again, reduces the risk of outages. And I described how impactful that has been over the last five years for DEP North Carolina from those trees falling from outside the right-of-way. This is a prudent utility practice and has been. We've been doing this for years to remove those threats that we identify outside the right-of-way as well as properly maintaining those inside the right-of-way.

And lastly, infrastructure integrity. I talked about this a little bit earlier but back to that house analogy. All the other programs I've described are doing -- they're more like the house remodel. They're looking above the ground. It's the things that we need to add to the grid and improvements we need to make there, but we also have to look at all of the infrastructure that's served or part of these MYRP projects and make sure the foundation is in good condition. Same thing for that remodel. You wouldn't do all or spend all those dollars to improve everything above the ground if you've got a failing foundation or problems that need to be addressed before doing that work.

Some examples of this you'll see in the bottom, in the program description. That would include inspection-based asset replacements. It could be transformers that have been inspected as well as poles. Oil mitigation where we have opportunities to upgrade equipment from hydraulic to solid di-electric removes oil off the system. Distribution does have some SF6 gas insulated switch gears. Those are typically vault-mounted switch gear that we now have the option to replace with modern solid di-electric so we can remove that SF6 gas from the distribution grid.

Technological obsolescence, that's one that's listed there. That one specifically say recloser controls, but that could also apply to regulator or capacity or other electronic devices on the distribution grid that have a control panel. And the obsolescence could be a couple of things or multiple things. It could be one that doesn't fit our cyber security requirements now. It could also be one that the vendor is no longer supporting. It's actually functioning, but if it fails, we can't find parts or do any replacement and so we've upgraded that to a modern. Or the example I gave earlier, technological obsolescence for voltage regulators. The current controls cannot control voltage in two different directions. They are simply looking from the substation out to control voltage. The modern controls can determine a stiff source from either direction and properly maintain voltage. And there's a couple of other examples also.

And lastly, the benefits for infrastructure integrity, again, reliability and resiliency, it reduces the risk of outage due to unplanned replacements or failures. Sustained infrastructure integrity enables more efficient restoration when there is an event that we need to deal with -- oh, sorry. I lost my train of thought there for a second -- also for the customers and the experience. Having planned replacements of these assets is much less impactful than unplanned events, whether it be an outage or doing those individually. We do those as part of our overall MYRP projects. As I stated earlier, we mobilize in -- uplift the infrastructure, including this work, and then move on to the next area.

That concludes the distribution projects. I'll now turn it over to Dan Maley to talk about transmission projects.

CHAIR MITCHELL: Why don't we pause here and let me check in with Commissioners to see if there are questions for Mr. Guyton on his presentation. Commissioner Clodfelter, go ahead.

COMMISSIONER CLODFELTER: I have several questions but they're not specific to distribution. But, Mr. Guyton, I've got one for you that is specific to distribution, and let me preface the question with a comment. Way back in the dark ages, before the pandemic, I remember the Technical Conference at which you came at and presented the plans for ISOP, and I wanted to just say to you that listening today, to some of what you went through, is a really good feeling to see what's come to fruition over the course of the last three years as you've implemented the ISOP initiative, and to see some of the fruits of that today is good. I appreciate it. I remember when you were just starting the journey, and it's good to see the progress you've made along the way.

The question really relates to the capabilities of MoreCast and how it works. And I'm really intrigued about how, when you're, sort of, running a MoreCast, a forecast of a circuit and try to identify, sort of, the three to five-year needs on that circuit for various investments on the circuit. You tell me if I'm wrong, but I'm assuming that within forecast, within MoreCast you're not able to model endogenously within MoreCast the adoption rates of EVs on a particular circuit or installation of rooftop solar or other DERs on that circuit or that substation. MoreCast can't do that modeling, can it?

MR. GUYTON: There are some -- good question. There are some assumptions made. And I don't know the absolute details of the algorithm, but it does look at certain factors that an area would be more prone to adopt EV or rooftop solar. Again, I don't know the gory details of that, but it does assume based on customers and other things of who might be and what areas might be more prone to adopt faster in those cases.

COMMISSIONER CLODFELTER: Well, that's intriguing because that's really -- well, you're getting at the heart of really what I wanted to explore was whether or not you provide, sort of, a certain level of EV adoption and a certain level of rooftop solar within the service area of a given substation and just provide that as an external input to MoreCast and then say solve for that level of DER and EV adoption, or whether the model itself can generate some of that.

MR. GUYTON: So my understanding is there are multiple data inputs into the model that -- then it calculates what that propensity to adopt EV or solar is as opposed to just having a -- here's an EV number or here's a DER number from that. But I don't know the detail specifics of the algorithm that does that.

COMMISSIONER CLODFELTER: Wow. That's really interesting to hear. And so at least a follow-up question which is do you then feed those results upstream to the resource planners and say, "Look, we're a -- when we run MoreCast across the distribution grid, we're seeing this rate of EV adoption and you should expect this many EVs on the grid within five-years time". Do you share that information with the resource planners?

MR. GUYTON: Yes. And actually, MoreCast is part of truly the ISOP tool set, so it's part of ISOP. The planning engineers actually leverage that for load forecasting for an individual circuit, so it's actually -- the critical part of it is to inform the overall Integrated Resource Plan. We're leveraging, like I said, the first five years of that forecast to look at actual planning for distribution projects that -- infrastructure projects that need to be executed.

COMMISSIONER CLODFELTER: Outstanding. So, let me ask the ultimate $64,000 question. So when I read the IRP or the Carbon Plan, which we're currently reading, either one of them, when I read those documents and I see sort of a projection of how much rooftop solar is going to be out on the grid over the course of the planning period, I can say that's an output. In large measure, it's an output from the MoreCast forecasting process?

MR. GUYTON: I was not part of the Carbon

Plan development, et cetera. That would be by assumption, but it would need to be validated, but I would expect that.

COMMISSIONER CLODFELTER: That's very interesting. Thank you for that. That's very helpful. That's my question. Thank you.

CHAIR MITCHELL: Additional questions? I'm unable to see Commissioners Duffley, Brown-Bland and Hughes, so if you-all have questions, you need to let me know because I can't see you right now.

COMMISSIONER DUFFLEY: I have a question. It's Kim Duffley.

CHAIR MITCHELL: Okay. Go ahead, Commissioner Duffley.

COMMISSIONER DUFFLEY: So you may hear from other Commissioners asking about SAVe and SAFe, but in the presentation I heard a lot of benefits regarding reducing outages as well as the length of the outages. And so my question is what are your current SAVe and SAFe metrics right now compared to your past two rate cases and, you know, generally are they trending up or down?

MR. GUYTON: Commissioner, off the top of my head, I don't have that information in front of me. I think they're -- I can -- specifically for self-optimizing grid, that has a substantial impact on reliability. There's a lot of other impacts so I don't know the overall system numbers and how those are trending at the moment, but the impacts of -- if just as an example, for the self-optimizing grid work that we're proposing to execute in this time period, we expect -- I'm sorry, I'm looking. I have a number here that I had captured for this purpose -- an additional 21 million customer minutes of interruption saved just for the self-optimizing grid work that we're proposing in this MYRP plan. So I apologize for not having the rivalry numbers tied to the rate case time periods, but quite a bit of this --

COMMISSIONER DUFFLEY: That's okay. We can find them. I just wondered if you knew off the top of your head while we're talking about it today. So thank you for that answer.

And then my one other question is when you went over the infrastructure integrity program overview and benefits, and you may have said this and I missed it, but all the -- most of the other ones have the total benefits, you know, gave that benefit cost ratio, and this program did not have that. And what is the reason for not having it with this program?

MR. GUYTON: Yeah, thank you for asking. So infrastructure integrity is work that we -- we see that as an obligation to serve as a utility to maintain the foundation, whether we're doing other reliability improvements and things above the norm. This is simply maintaining that foundation. And so I guess the example I would give is if I have -- kind of back to my analogy earlier -- if I'm going to do that house remodel but I've got a foundational, foundation issue, I certainly may get different bids from vendors, but I'm not going to not fix the foundation. It's just work that I have to do from that perspective. I wouldn't do a cost benefit of, okay, if the foundation fails, here's what will happen versus spending the money to fix it. I'm going to fix it from that perspective. So that was the reasoning there.

COMMISSIONER DUFFLEY: Okay. That makes sense. Thank you. I have no further questions.

MR. GUYTON: Thank you.

CHAIR MITCHELL: Additional questions?

Commissioner McKissick.

COMMISSIONER McKISSICK: Sure, just one or two. In looking at your cost-benefit ratio, of course it varies from project to project. Some may be down at 0.5 percent and others up at 8.1. What methodology that you use for establishing the cost-benefit ratio for these particular projects? And I guess that question also applies to ones that we're going to get into later in the next session of the presentation. Could you be -- could you elaborate further on the methodology that was used?

MR. GUYTON: Absolutely. So I would offer overall we leveraged a similar methodology as we have in the past.

COMMISSIONER McKISSICK: Okay.

MR. GUYTON: And at the core of that is the ICE calculator, Interruption Cost Estimating tool. Based on feedback from this Commission and staff previously from those other filings, we not only use the ICE calculator, but also specifically using the online version, created our tables specific for North Carolina as opposed to the standard tables that are part of the ICE calculator. And those went into our traditional cost-benefit analysis tools of here's all the costs we have, here's the benefits, not only from the ICE calculator but our cost to restore the outage, and under their factors such as that.

COMMISSIONER McKISSICK: So is the ICE calculator and specifically the ratios applicable to North Carolina?

MR. GUYTON: That's correct. We generate -- from the online tool you can go in and actually pick the state -- I can't remember the other criteria that's there -- and actually, it will generate value that then we specifically took those values and put them into our CBA analysis tools that --

COMMISSIONER McKISSICK: Thank you. Did you consider employing or utilizing any other tools or methodologies for calculating the cost-benefit ratios?

MR. GUYTON: Not that I'm aware of. The ICE calculator is the only one that I'm personally aware of that's an industry-accepted. It was funded by the DOE. They're going through some updates I think to the tool now that we will probably see maybe in 2024 or 2025, including more utilities, different surveys, and updated data from that. So, that's the only one that I'm aware of. But that is what we use, sir.

COMMISSIONER McKISSICK: Sure. Thank you. And I guess the other question is kind of a follow up to what Commissioner Clodfelter asked you.

The thing I'm trying to determine when you're looking at say adoption of EVs or adoption of rooftop solar. At least for rooftop solar, we have a pretty long established track record for the EVs. It's not so great. How do you sit back and extrapolate what that adoption rate might be, particularly since it could be linked to other external factors that you may not have control over, like the price of a barrel of oil.

MR. GUYTON: Good question. And I guess I'll have to answer it the same way I answered Commissioner Clodfelter's question, is I don't know the details, but it does look at multiple factors and incorporate those of what may drive someone to select an EV. I don't know if it looks at economic data of household income and other statistical information, but leverages that to look at both historically where you've seen DER adoption, what tended to be the drivers there. And I think they're making some assumptions, of course, and trying to bottle what do we think the EVPs will be like, based on the best data that we have from that perspective.

COMMISSIONER McKISSICK: Thank you.

CHAIR MITCHELL: Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Let me follow a little bit on one of the questions that Commissioner McKissick asked you. I was going to hold it til the end because it applies to transmission as well, but since we've got the topic on the table, let me go ahead and ask it.

In the last -- the Company's last general rate case, Public Staff witnesses Thomas and Williamson and a couple of the Intervenor witnesses made some very detailed recommendations about how Duke should revise and adjust its cost-benefit analyses, changes to data sources and inputs, as well as changes to methodologies. Other than what you outlined to Commissioner McKissick, what other responses did the Company make to those suggestions from the Public Staff witnesses?

MR. GUYTON: Besides the one I specifically referenced of that very specific North

Carolina table, I personally do not know what those changes may have been. I know there was a lot of discussion and intake of that into looking at how we would modify those. But that's the one I specifically know of. I'm not saying that others weren't done or addressed, but I do not know the answer to that question.

COMMISSIONER CLODFELTER: I predict that's going to be a topic of some questions in the rate case themself, and so it's good to go ahead and get the question on the table for you today so everybody can be thinking about it.

Let me ask you about one specifically and see if it jogs your recollection. The Public Staff suggested that the Company run sensitivities to various -- to different variables using the cost-benefit analyses and that that was not done in the last series of studies that were presented in the last rate case. Do you know if in the current modeling of cost-benefit analysis that you've got summarized in these materials where the different sensitivities were ran -- were run on different variables?

MR. GUYTON: I do not know for sure.

COMMISSIONER CLODFELTER: Don't know?

MR. GUYTON: No.

COMMISSIONER CLODFELTER: Okay. Again, I --

MR. GUYTON: We did not run multiple cost-benefit analyses for sensitivities.

COMMISSIONER CLODFELTER: Okay. Just forecasting questions for the general rate case.

MR. GUYTON: Absolutely.

COMMISSIONER CLODFELTER: Trying to help you guys out. That's all.

CHAIR MITCHELL: Commissioner Kemerait.

COMMISSIONER KEMERAIT: Thank you for your presentation. Just following up on Commissioner Duffley's question. In addition to the infrastructure integrity program, I also did not see a benefit-cost ratio for the hazard tree removal program. Is there a reason why that program also does not have the ratio?

MR. GUYTON: Great question. And really it's the same answer. This is an obligation to serve. We have a known threat to infrastructure and the trees need to be removed.

And I guess another analogy I would give is if I've got a tree leaning over my house that's posing a threat - it's dead, dying, or an arborist tells me it's dead, dying or structurally unsound - I certainly may get bids from competitive vendors to take it down and choose the one I think is appropriate, but it won't be a cost-benefit analysis if I don't do anything versus doing anything. It's a known risk that we -- we see that as obligation to serve.

COMMISSIONER KEMERAIT: Thank you.

CHAIR MITCHELL: Commissioner Brown-Bland, I see you on camera. Do you have a question?

COMMISSIONER BROWN-BLAND: No, no question.

CHAIR MITCHELL: Mr. Guyton, I have a few for you. We'll stick with hazard tree removal since Commissioner Kemerait was just talking to you about it. How does what you-all have proposed here are compared to what you-all are currently doing with respect to hazard tree removal?

MR. GUYTON: We're removing hazard trees now. This is simply --

CHAIR MITCHELL: A continuation of --

MR. GUYTON: -- a continuation of that

work. We feel like it meets the requirements for inclusion in MYRP. But it is the -- I mean, the process and what we do and how we do it is exactly the same.

CHAIR MITCHELL: Okay. And level of spending would be similar to what you're spending now?

MR. GUYTON: To my knowledge, yes. We're doing that work now.

CHAIR MITCHELL: Okay. And did I hear you correctly, if I didn't correct me, when you said 50 percent of vegetation management-related outages caused -- that the Company is experiencing now are caused by trees from outside the right-of-way?

MR. GUYTON: That is correct.

CHAIR MITCHELL: Okay.

MR. GUYTON: And that's not just the average over the last five years. Every single one of those five years, it is above 50 percent. It moves from, I think it was 51 to 56 percent, but consistently it is over half of the vegetation outages.

CHAIR MITCHELL: Okay. You also discussed today, with respect to the capacity program, outages due to overloaded conductors. Is the Company experiencing overloaded conductors from associated with DER penetration or customer load at this point in time or is that -- or is the Company anticipating that?

MR. GUYTON: Is the question are we experiencing overloads or are we experiencing failures due to overload?

CHAIR MITCHELL: Well, overloaded conductors.

MR. GUYTON: By our planning analyses, there are conductors that are technically overloaded.

CHAIR MITCHELL: At present, there are overloaded conductors?

MR. GUYTON: At present. Specifically, I couldn't tell you or give you a specific example of this one is overloaded because of DER, but we are constantly looking at thermal overloads and then addressing those appropriately; whatever the drivers are.

CHAIR MITCHELL: Okay.

MR. GUYTON: In capacity and in our forward-looking capacity we are, as the other questions have come about MoreCast and how it views EV adoption and DER, we are looking to create additional headroom or hosting capacity on those circuits and not get to an overload situation, even with EVs and DERs coming from that perspective. So that's the -- you know, if traditional planning was here, there's another layer of capacity here (indicating) to be able to deal with those modern technologies and their impacts.

CHAIR MITCHELL: Okay, thank you for that. Some of the -- as I have understood what you-all have -- what you've described today, some of these programs would seek to prevent faults and some of them would seek to mitigate the impact of faults. You've described the self-optimizing grid would mitigate the impact of faults on, you know, customers on the circuit. So, how do you-all prioritize spending on programs that prevent fault versus mitigate impacts of fault?

MR. GUYTON: So, what I would offer is that what we're proposing here is a comprehensive plan so we're addressing both. It's an "all of the above". One, we need to make sure that we can never -- we can never build a grid that would never have a fault. That's not a practical thing to do or couldn't afford it even if we could do it and so we address both. Certainly, the intent is wherever we have identified ways to prevent faults and do that with a cost-benefit analysis, make sure it's worth the money to do, we're going to try and prevent the fault first. If there's not a way to simply prevent the fault from ever occurring, let's make sure we minimize the impact to many customers, and that's why what you'll see is on the laterals. It tends to focus more on fault elimination or trying to prevent it from being an outage; whereas, on self-optimizing grid, we know we're going to have those things impact significant numbers of customers, and so they are -- while we still do work to try and prevent the faults - vegetation management - a lot of the equipment retrofit work, that will be on laterals and backbone circuits. Wherever that equipment exists, that's where we would apply that and that is fault. Trying to eliminate faults as opposed to just preventing the impacts. So I'm not sure if I answered your question.

CHAIR MITCHELL: You did. The Commission in the most recent rate case orders directed the

Companies to work with -- I think it was at Vote Solar's request. Let me get my notes. It's Vote Solar. A stipulation that Duke entered into with Vote Solar to form a Climate Risk and Resilience Working Group to identify vulnerabilities on the grid and potentially solutions for those vulnerabilities that result from severe weather impacts. Is any of this work informed by the work of that group, to your knowledge?

MR. GUYTON: So, I'm going to say no, but let me preface this with this. My understanding of that Climate Risk and Resiliency Study is looking further out in the future for threats into the future. And then once those threats are identified with that, I guess the first part of that study, then what would potentially be changed in design standards or other things for that decades-out look, and so this work is focused on what we know now and what we do so. I'm going to say I'm not aware of any --

MR. BROWN: I can add, too, that I've seen a draft report of that. I think it's going to be issued very soon that the work that we have contemplated in for T&D is not counter to anything that's going to be found within at least the initial inputs from that particular study.

CHAIR MITCHELL: Okay. How are you -- are you-all assessing weather-related risks the same way for the purposes of this nearer-term activity versus perhaps the longer-term analysis that the Climate Risk and Resilience Group is undertaking?

MR. GUYTON: I'm not sure I'd answer that with a yes, but what I will say is that that storm hardening resiliency that I just spoke of, recognizing the frequency and severity that we have of both winter and tropical events now, is looking very specifically at those areas that we've seen impacted repeatedly in the past and then applying Grade B construction and NESC-D -- NESC ice loading criteria for those. I would not be surprised if in that climate study at some point it references higher standards of strength for the grid because of future threats for that. So I think, as Justin said, it's in line with where we believe that study will go, you know, strengthening the grid. And so I don't see that being counter to it, I think it's supportive. We're out in front of it, again, looking at severe weather impacts.

CHAIR MITCHELL: Okay. And so as you -- to identify severe weather impacts or severe weather risks to DEP's grid, what data are you relying on? How are you analyzing that?

MR. GUYTON: So it is looking at the locations where we've had previous damage from tropical events as well as winter events, and looking specifically at the outage-caused codes. If it's a storm outage-caused code, the dates line up with when we had one of those major events because those typically are major event days. We had that data to look at and say where do we see damage? Let's assess those areas and see if it needs additional strength for ice loading or high winds from tropical events.

CHAIR MITCHELL: Thank you. That helps me. Several Commissioners have asked you about benefits, program benefits. You've discussed them at length here today. In some cases they've been quantified. The more -- I'm curious and ready to learn more about how the Company is identifying benefits and quantifying them. So, the more that the Company can help me, as a Commissioner, understand that, how you're identifying benefits and quantifying them, would be much appreciated.

MR. GUYTON: Okay.

CHAIR MITCHELL: That was a comment more than a question. Let me just look through here and see if there's anything else I want to ask you.

Maximum ambient temperature. Is there a -- is the distribution system designed to maximum ambient temperature for optimal operation at this point in time?

MR. GUYTON: I know that in our conductor ratings, air temperature is taken into account. I don't know if they look at maximum ambient or not. I'm not a standards engineer.

CHAIR MITCHELL: Understood.

MR. GUYTON: There is temperature, you know, variations based on sag because that's how we develop our spacing all on the poles.

CHAIR MITCHELL: And do you anticipate that changing ambient line ratings or your taking into account of temperature ranges?

MR. GUYTON: I would think that a climate resiliency study is going to point to things of that nature. If they truly are identifying a change in temperatures, that would be incorporated, because we would assume our normal temperatures are greater. But I --

CHAIR MITCHELL: Well, I don't necessarily -- I mean, for purposes of your operations, allowing your, sort of, greater temperature fluctuations for purpose of your operations.

MR. GUYTON: I do not know, but I would think that would be taken into consideration both for operational practices as well as design standards.

CHAIR MITCHELL: Okay. So, it's not something that you-all are considering right now is what I'm taking --

MR. GUYTON: It is not part of the -- that we are leveraging for this work, our current design and construction standards for this work.

CHAIR MITCHELL: Okay. And one last question for you and this is mostly to make sure I am reading this correctly. Back to the hazard tree removal program. Are you-all proposing to capitalize certain expenditures associated with that program?

MR. GUYTON: Work outside the right --

work inside of our maintained right-of-way is O&M costs to maintain that. Doing work or expanding -- not really expanding the right-of-way -- doing outside is capitalized. I'm not an accountant but that's my understanding of how that work is treated outside the right-of-way versus inside.

CHAIR MITCHELL: So to the extent that these costs are shown as capital costs would be due to the fact that work is being conducted outside the Company's --

MR. GUYTON: Correct.

CHAIR MITCHELL: Okay. Go ahead, Commissioner Clodfelter.

COMMISSIONER CLODFELTER: Mr. Guyton, sorry I didn't think of this earlier. I apologize. With respect to the LDI program, I'm reminded that one of the justifications or the principal justification for the Hot Springs microgrid was to solve an LDI problem, but I don't see that identified as one of the options for the LDI program. Should I draw any conclusions about the success or failure of the microgrid at Hot Springs or is there some other reason why that's not an element or a potential option for dealing with LDI situations?

MR. GUYTON: I don't think that should be taken as any reflection on Hot Springs. Things I've heard and seen from that, I'm not keyed on that project, but things are moving along appropriately for it.

In this particular case with -- I think Hot Springs had some unique abilities to take on that type of project. But certainly, as we look at capacity or other upgrades like that, a non-wires alternative is part of our analysis in that.

For the long duration interruption, it typically is not like a Hot Springs where you've got -- I don't remember the number of customers, but that whole little village was impacted. These tend to be smaller but they're the customers that see those every time we have a major event or there's an outage, even in blue sky days. It's long to get to them and get them restored just because of the access to the lines. Hot Springs had that challenge, too. It was remote terrain at Hot Springs.

COMMISSIONER CLODFELTER: So again, help me understand why that would not be one of the weapons in your arsenal for solving long duration at Hot Springs?

MR. GUYTON: I think it certainly could be. But for these, the cost of being able to relocate to the roadway was much cheaper than battery alternatives for these on those.

COMMISSIONER CLODFELTER: So these are -- we look at these as low-cost solutions?

MR. GUYTON: They're low cost. And I would offer -- I'd have to go back and look at the projects, but the number of customers impacted is much less.

COMMISSIONER CLODFELTER: Is much less than in the Hot Springs case.

MR. GUYTON: Yeah, Hot Springs.

COMMISSIONER CLODFELTER: So do you -- where would I look if I wanted to look in here and just find where you're going to address similar situations or opportunities, I should call them, like the Hot Springs opportunity. Which program would sort of speak at --

MR. GUYTON: That would actually be in capacity. So, if we have --

COMMISSIONER CLODFELTER: In capacity.

MR. GUYTON: If we have capacity projects where traditionally we would propose a wires alternative, so typically upgrading wires or equipment, that's where we would do a non-wires alternative review for that. We've done some of those. We haven't had one that that was the least-cost opportunity or option to do those, but we're continuing to do those. And I would expect over time if costs moderate after the global uncertainties in those spaces, that you would see those start to move into that space.

COMMISSIONER CLODFELTER: Okay.

MR. GUYTON: But we are constantly leveraging our Energy Storage Group looking for places to deploy additional battery-type assets.

COMMISSIONER CLODFELTER: Thank you, sir.

CHAIR MITCHELL: Last question from Commissioner McKissick.

COMMISSIONER McKISSICK: And this is just kind of a more of a curiosity than anything else. I noticed in the distribution hardening and resiliency Program, it refers to you planning on using, assuming a Grade B, and NESC standard 250 BA. Why did you decide to use that as the standard as opposed to whatever Grade A would have been?

MR. GUYTON: So I'm not a standards engineer, but my understanding of that is, that is a higher level of strength --

COMMISSIONER McKISSICK: Okay.

MR. GUYTON: -- grade B, than what our typical construction is. And in the NESC loading criteria, I think it was 250B-D, that's actually looking at ice loading, and that's looking at -- that's -- which our historical grid we have not had that type of activity. We've always had some ice, but they're getting more severe. A heavier application of ice, so that's why we're looking at those areas and saying let's move up to a higher level of strength in those areas, whether it be for ice loading or wind loading, and that's what those are addressing.

COMMISSIONER McKISSICK: So I take it that what you're doing is improving the standards that have been historically utilized, perhaps not going completely to a point where it may not be cost beneficial to go to that extra level of improvement?

MR. GUYTON: That is correct. And we're also targeting specific areas, so that wouldn't just be changing distribution standards to go all Grade B construction everywhere. It's, hey, where do we actually have high wind loadings, so we'll look at those coastal areas, again, looking at our data where we've had structural damage from high winds in previous storms, and then looking for opportunities to make those changes to the --

COMMISSIONER McKISSICK: Can I take in prioritizing those areas, do you look at service interruptions or problems that have occurred in the past? Is it that typically historical data?

MR. GUYTON: It is the number of customers that are served. And once we've made those improvements, what would the benefits be, and leveraging those that are the highest benefits in those areas.

COMMISSIONER McKISSICK: Thank you.

CHAIR MITCHELL: At this point, we're going to take a short break for the court reporter. We will have a recess and we will come back on the record at four o'clock. Thank you.

(A recess was taken)

CHAIR MITCHELL: All right. Let's go back on the record, please.

Mr. Brown, y'all may continue.

MR. BROWN: Thank you. Mr. Maley?

MR. MALEY: All right. Good afternoon. I'm Dan Maley. I'll be speaking to our transmission projects.

We are going to start off with an overview of the project areas, and then I'll be drilling down into some specific project locations. One thing I'll mention off the bat is you will notice some similarities between the distribution programs that Mr. Guyton spoke of and the transmission projects that I will speak of. Some of the terminology is a little bit different whereas distribution is arranged in terms of programs and projects in transmission. Portfolios are arranged in terms of seven unique transmission projects. And then result in project locations where we are actually implementing the work. I will talk through some of the details there.

The commonality really between the two is we are both bundling work in common geographic areas to most effectively and efficiently plan and design and schedule and implement the ultimate work.

I'll start off by describing some of the characteristics that will be enabled by the transmission project areas. System intelligence, the first category here, we're really improving grid awareness for our grid operators and engineers through the installation of intelligent field devices that get more information back to our operators so they can make smart decisions about manipulating the grid restoring customers.

Our hardening and resiliency projects similar to what you heard for the distribution system. We are targeting a more -- a stronger and more resilient grid through both the prevention of faults and the mitigation of faults when they do occur.

Our transformer and breaker upgrade project. This is really about preventing the impacts of future failures. We're targeting assets that are at end of life and we are proactively replacing those prior to failure, prior to the point that they cause either a direct outage or a voltage sag on the grid that can impact our sensitive industrial customers or other problems.

And then finally capacity and customer planning. This is about meeting customer and capacity demands and obligations. Under the transmission system we're obligated to meet our NERC reliability standards. We're also obligated to meet our new customer connections for commercial/industrial customers and of course, coordinating with our distribution department for retail customer needs.

I'll introduce here a view of the -- the portfolio view of the transmission projects. What you can see on the left side is sort of the investment view. This is the Duke Energy Progress system level investment across the various project areas. And I'll talk a little bit more to the various improvement categories here on this slide.

I mentioned intelligent equipment upgrades under our system intelligent project. This type -- this is installing digital relays that have much more capability than the Legacy electromechanical devices primarily made up of cams and levers. Again, this is getting more information back to our grid operators.

Hardening and resiliency is broken down into several categories. Transmission line hardening and resiliency. This is really upgrading structures. You think about replacing wooden structures with steel structures for our H frame. We'll see some pictures of that. And also replacing transmission towers that are at the end of life or subject to failures due to certain degradation mechanisms.

And when we upgrade these towers and structures, we're rebuilding them to the latest standards capable of withstanding more extreme weather events. This project are is particularly beneficial during those storm events and extreme weather events.

Vegetation management, very similar to the customer delivery project. The hazard tree removals, we are targeting our outside of the right-of-way. We identify threats. We remove the trees that could result in threats and impact the transmission system.

The transformer and breaker upgrade project area, both of these projects are about targeting assets that are at the end of life, proactively replacing those assets. And at the same time we're upgrading the capability of those assets. So when we replace a circuit breaker or we replace a transformer, we are installing in parallel to this upgraded communication devices, protection and control relays, again, to be able to better control that equipment, restore that equipment following an outage condition and get more information such as system voltages and currents and power back to our grid operators and our grid engineers responsible for end-of-life planning.

Capacity of customer planning, this is our largest category of work here. You can see on the bottom of the stack, the VAR chart. This is expanding capacity for customers as load is added to the system, as resource population centers change and move around the state. We have to plan that into our substation and transmission circuit projects.

We're also informing these projects through our ISOP process that you heard of earlier. So as we look at a capacity need, we are screening that through our ISOP process to look, is three a nontraditional solution or a non-wires alternative to a traditional transformer upgrade or a circuit rebuild. And that's allowing us really to look at the best benefit-to-cost ratio for the given solution and move forward with implementing it.

This category of work also includes our transmission expansion projects. These are sometimes referred to as the red zone expansion projects. And what these projects are targeting is looking at the areas of the Duke Energy Progress system that have the maximum solar viability from ability to connect solar generation resources and we're overlaying those areas with areas of the grid that are constrained and I use the term maxed out or near maxed out. They are very limited to be able to add additional renewable energy resources and we are targeting upgrading those circuits and in some case substation equipment to accommodate additional renewable energy resources. For Duke Energy, this is a very important part of our clean energy transition to be able to deliver to our customers a cleaner energy future.

The secondary benefit of these projects is we're delivering reliability benefits. We're replacing aged conductor. We're replacing wooden structures with steel structures designed to the latest standards. And we're hardening those systems as we rebuild the circuits.

The last thing on this slide I'll mention is the cost by the overall project as well as by the project location is included in the transmission details exhibit. And I will note that the project location details and costs are as of early June timeframe and these projects continue to be refined as we move them through our development and estimating process under our project management process, particularly those projects in the outer years of the three-year multi-year rate plan.

So as those advance in maturity between June and when we ultimately file the rate case, we will expect to see some changes in both in-service states and costs associated with these projects.

I'd like to talk a little bit about how we've built the transmission multi-year rate plan portfolio and how we've selected the project locations that are included.

What you see in the middle of this slide are our two different organizations; our system planning organization -- again, similar to Mr. Guyton talking about distribution planning engineers, transmission planning engineers are looking at capacity needs for the system. They're working very closely with our distribution planners and our generation planners as well.

Our system planning engineers are also responsible for our NERC compliance obligations ensuring that we meet the obligations of the North American Electric Reliability Council and that as we model the transmission system and model certain failure scenarios, we will not overload the system, we will not result in catastrophic impacts, cascading impacts, brown outs. So those planning engineers are responsible for that part of the portfolio.

The asset management engineers and subject matter experts are really about end-of-life planning. So I mentioned predicting where we're going to have future failures and preventing those failures. Technology upgrades to facilitate a smarter grid that is more capable of providing us information on where failures will occur, where problems on the grid are occurring.

So we take various different inputs from field inspections, from asset health trending, technician and lineman input, industry and industry data, and we take that information, we target the specific location that needs work, and we initiate and we score that project in a variety of areas. And what you can see around the outside of the circle here are the different areas that we're looking at from a benefit to cost prospective.

We use a third-party software that is specifically designed with various value models to build a benefit. And in terms of each specific project location, we score that project to -- in the various value models to determine that benefit. So we're looking at financial risks, security and safety, compliance with our regulations, environmental and property impacts, grid capacity due to growth and changing demands. And then, of course, reliability and integrity. Pause for a moment.

Reliability is really the largest area from a benefit perspective. Similar to the customer delivery organization in the distribution grid we're using the ICE calculator to determine the cost of an avoided outage or essentially looking at what is -- if we can avoid this outage, how do we monetize that cost and how do we use that as the benefit that would be achieved through the product -- through the project in that specific location.

And again, similar to Mr. Guyton, we are using DEP specific information. That ICE calculator is actually embedded in our third-party software that we're using for this prioritization framework. Again, we worked through the benefit to cost analysis for those locations and the most beneficial projects are optimized and ultimately built into our multi-year rate plan.

The last thing I'll mention is we are evaluating the specific different mix of customer classes when we look at a benefit, so we're using three different classes; residential, small C&I, and then large commercial and industrial as well to factor into our benefits.

I'm going to start diving into our specific project areas and I will talk mainly about the description of the project and then I'll get into the benefits of these projects and we'll look at one specific project location in each of the seven areas and talk about what that looks like.

So what does system intelligence mean? Quite simply as I mentioned earlier, it's our ability to obtain more useful data about the grid and about our assets, so that we can make smart decisions in the best interest of the reliability of our customers.

Digital relay. As you can see in the bottom right picture, these blue boxes on the screen are digital relays. They're small computers that are installed in place of traditional electromechanical devices.

What is a relay? It's simply a device that senses a problem on the transmission grid, generally a fault condition, and it sends a signal to a circuit breaker to open the breaker and isolate the fault. We're very interested in keeping faults isolated the smallest possible section of the grid and that minimizes the impacts on customers when we can effectively do that.

These digital relays are not only more reliable in sending those signals to circuit breakers and very quickly in a matter of fractions of a second isolating faults, but they also provide supplemental information to our operators and to our engineers.

The historical means of actually finding a fault on a transmission line, you can think of a long transmission line maybe 30 miles or more, when we have a fault, we have no intelligent devices telling us where that fault occurs, our energy control center only knows that the breakers on each end of this line opened. Somewhere in the middle of this 30 miles we have a problem. We have to dispatch linemen and start driving down right-of-ways. In some cases it's very difficult to access these right-of-ways. They're not generally along roadways.

With intelligent devices, we have a better idea and in some cases a very specific location down to the structure number on where that fault occurred. We can use technology and algorithms to take that fault current that comes into our system, plug that into an algorithm as I mentioned and determine the distance to fault. We can then dispatch the lineman directly to that location. They can assess the problem. They can determine if there's a switching solution, which I'll talk a little bit more about in another project area, and then -- or they can determine if there's a repair that they can immediately make. Perhaps it's cutting a tree off a line. Perhaps it's replacing an insulator that was damaged by lightning. This is the real benefit of our digital relay upgrade project area.

Remote asset monitoring is the second item I'll mention here, both remote asset monitoring and substation monitoring. Most folks are familiar with traditional SCADA which is getting information from substations back to the control center, being able to control that equipment.

When we talk about asset monitoring, that takes SCADA down to the level of a specific asset. In this case transformers. Transformers are a very important asset on the transmission grid. They are transforming voltage from various different levels within transmission voltages and down to distribution levels to distribute it out to customers on the grid.

When these transformers can tell us hey, I have a problem, I am sick, I need attention, that's a huge benefit. I'll share an analogy here. I recently received an email and taking a look at it, it said your printer is low on ink. Very simple technology said your printer is low on ink. You have X amount of pages left to print before this asset fails. That's the type of technology that surprisingly many places of our transmission grid we have not yet implemented because the technology is relatively new.

This condition-based monitoring technology where we can have an in-line gas meter analyzing potential fault gases that are accumulating and are critical power transformers sending that information to our engineers and subject matter experts so they can make these decisions on essentially how long do I have before this transformer fails or before I need to take it out of service to proactively inspect it or do some additional maintenance. So that's really our asset monitoring program.

Remote switches I'll talk about more on our next slide here.

I'm going to go back to the example of when a line locks out. So we have a fault on the transmission system and two breakers at either end open. The transmission system is constructed with various line switches. These are large switches at the 230-kV and 115-kV levels generally and these switches do allow some operational flexibility to be able to further segment faults and isolate those faults down to smaller areas so then we can restore customer retail stations. We heard discussion about retail stations earlier which serve the majority of our customers.

Traditionally these switches are manually operated. So again, that lineman, once the fault is identified, once the location is identified, they will then have to drive to a switch which could be multiple miles, tens of miles away from where they're at. Open the switch using a crank handle. Notify the control center that now they can restore load using breakers at the substation. And the control center can make that action.

We are deploying more remote operated switches built in new locations and upgrading manual switches with these remote operating switches. This gives the capability for grid operators to be able to make those switching manipulations remotely from the control center. When we combine that technology with digital relays that give the location of the faults, we go from a matter of hours to resolve a transmission outage to minutes.

So there is still some manual action from the control center required, but it can be done in a matter of minutes and I would call this program somewhat akin to the self-optimizing grid program on the distribution side. It's really a significant way to mitigate the impacts of a fault or an outage occurring on the transmission system.

This specific project location is the Delco Whiteville remote control line switch installation. This transmission circuit is in the coastal plain area of North Carolina. It's susceptible to flooding. It's in low-lying areas. You can see kind of a swampy area in the bottom right picture on this right-of-way. It's very difficult to access. When we have a lightning strike or a tree that comes down onto a line or some other it could be a component failure itself, a structure failure perhaps during a weather event or a hurricane event, it's very difficult to access and restore and make that repair. By having these remote operated switches, we can really tighten up the area of the faulted segment of line, restore more customer load in a faster scenario.

So this specific project improves the reliability for more than 11,000 customers directly served off this transmission line. And that's from four separate substations.

The line hardening and resiliency project will be the next one I'll discuss. Several different areas where we're targeting improvements in this area.

First one is our cathodic protection project. You'll see down in the bottom left a picture of a failed transmission tower. This tower actually came down during a hurricane event and postmortem inspection revealed that the tower legs were corroded. Many of our transmission towers are direct embedded into the ground, which means their support structure maybe embedded underground so they're subject to groundwater and soil corrosion environments.

When we install a cathodic protection system, which is a series of protective anodes actually attached to those tower legs, we are protecting and arresting and mitigating the corrosion on these metal towers and that greatly improves the structural integrity of these towers particularly again during extreme weather events where we have high wind scenarios where we have scenarios that are susceptible to cause damage to a transmission tower.

The targeted line strengthening for extreme weather scope, you can see a picture in the middle here. This is a typical H frame design transmission structure. This is very common in our territory on the 230-kV and 115-kV systems. What we are doing is replacing vulnerable and aged wood poles and upgrading them with steel poles.

When we replace a wood pole with a steel pole, we're designing that to the very latest standards. We heard about the NESC standards earlier. The -- in a coastal area for example a new pole that's installed is designed up to 140 mile an hour wind scenario, so that's a great improvement over the traditional design that in the traditional standards that were in effect when these poles were installed 50, 60, 70 years ago. So again, we're targeting specific poles that we have identified as degraded. We're upgrading them to steel and in most cases we've greatly reduced the chance of that pole failing during a extreme weather event or other scenario.

Transmission tower is very similar. We're targeting specific types of transmission towers that are susceptible to failure. In these cases the degradation is not just at the ground level, but it's up higher parts of the tower that we can't arrest the corrosion or the degradation through a cathodic protection, so we're targeting replacement. I'll talk about a specific example of that on the next slide.

The last one I'll mention is the animal mitigation project scope. And this is a specific project targeted at our 500-kV system. One thing that occurs on the 500-kV system is buzzards love to roost on 500-kV towers. You can see these as you're driving under systems down highways in certain areas past our largest transmission towers.

Buzzards result in contamination directly underneath where they roost and that results in flashover events and these flashover events are very significant on the 500-kV system particularly impacting our industrial customers. So when we have sensitive manufacturing companies connected to our transmission grid, the faults in the voltage sags that happen on the 500 system, they transfer down into the 230-kV, the 115-kV and even down in some cases to the distribution level voltage. By preventing those faults from occurring through animal mitigation coverups, we are eliminating that, the voltage sag, from that structure that the project is implemented on.

You can see the benefits in the CBA numbers here. I'm going to jump right into discussing a little bit more about this specific project location. This system, Mayo-Person 500-kV targeted line strengthening project. And what you see is the -- the picture on the left you see a bolted joint. These transmission towers have many hundreds of bolted joints. This specific line is designed a material called weathering steel and it's a steel material that has a corrosion patina on it. It's brown in color and ideally what that does is arrest and prevents any more severe corrosion from occurring.

What has begun to happen on these towers, though and this is a common issue in the industry with this design of transmission tower, is these joints, these bolted joints are actually expanding due to corrosion and they're creating tensile stresses on these bolted joint that will eventually lead to bolt failure and weakening of the tower.

The 500-kV system is really the superhighway right at the transmission system. You heard Mr. Guyton talk about the transmission system as really the highway system and if we think about the 230 and 115 system as our state routes, our 500-kV system is really those interstates, right? It's your I40s and I95s. It's very important to move large amounts of power around the system.

Our customers are typically not directly connected to this system, but it's very critical particularly in peak winter and summer seasons.

This particular line supports about 500 MW of network flow, which is enough power for 300,000 homes, so very significant amount of power flow through these lines and it is our mission to prevent the failure and the resultant emergent tower replacement costs and potential power flow impacts that could happen to our transmission grid if this was to occur depending on the type of year where this would occur.

The last thing I'll mention on this Mayo Person Project is the solution to address the corrosion concern with this type of tower. We looked at multiple different solutions, multiple different types of repairs and replacement options and replacing the tower with a non-susceptible material that is not subject to this corrosion phenomenon. It is selected as the best solution from a benefit to cost standpoint and ultimately the standpoint to be able to reliably serve our customers in all of our weather conditions.

Next slide is the substation hardening and resiliency project. Several different project areas I'll go through here. Substation rebuilds is the first one.

Substation rebuilds are all about replacing degraded wooden structures within our substations. Many of our substations that transmit power from the 230 or 115-kV system down to distribution level voltage is 24-kV, 13-kV in some places. Those are using wooden horizontal and vertical members.

So similar to the wooden transmission tower program, our substation rebuilt program is eliminating these wood structures. You can think about these wood structures as really the skeletal system of the substation. They are supporting and holding up the vital organs, right? The transformers, the breakers, the instrumentation that's really critical for delivering the power to our customers.

When the skeletal system starts to fail, the supported assets start to fail and what we're seeing is that these wooden structures are splintering, they're warping, they're causing equipment to come out of alignment and we're replacing those with steel structures. And at the same time we're upgrading our targeted breakers and transformers and system intelligence scope work that overlaps where there are other project areas.

The substation flood mitigation scope pretty straightforward. We are mitigating the impacts of floods. We are either relocating substations out of flood-prone areas or elevating equipment or in substation -- in some locations building a flood wall.

Animal mitigation. The animal mitigation scope is really installing animal mitigation fences around our substations. Animals are a very significant contributor to transmission outages. When an animal contacts equipment inside a transmission station, the design of the equipment is typically to lockout. So the breaker opens, right? This prevents more significant damage to equipment and collateral damage, so when animals contact lines or circuits, that's not always the case. Mr. Guyton talked about momentary impacts in -- when animals impact substations, it's a sustained outage that often impacts customers.

By putting in specialty fences, we're preventing snakes and squirrels and raccoons from getting into our stations greatly reducing the chance of an animal causing an outage.

Physical security. Very similar except instead of animals, we're keeping people out of substations. So whether it is intentional or non-intentional, our most critical substations we're installing high-security fences. We're installing intrusion detection equipment and other related equipment to make sure that we know the status of and again, keeping people out from causing intentional or unintentional damage or harm to critical transmission substations.

Specific example I'll mention for substation hardening and resiliency is our Raeford South 115-kV substation rebuild. You can see an example on the lower right of what these wooden structures look like that support equipment. And on the left is the transformer at Raeford South that we're targeting the upgrade on. And again, I'll talk more about transformer upgrades and the drivers there in just a moment.

But this is rebuilding this substation, replacing the equipment that is in need -- that is at end of life and is at risk of failure to prevent those future impacts to our customers. And again, eliminating those wooden structures upgrading everything to steel structures designed to the latest standards.

This is a smaller station. It serves approximately a thousand retail customers. Still an important station for our retail customers in the Raeford, North Carolina area.

Vegetation management. Our vegetation management project area is very similar to the distribution project you heard of earlier. We're really targeting hazard tree removals outside of our right-of-way.

What you can see in the image on the left tier is a scan that was taken from an aerial patrol.

All transmission circuits are patrolled using aerial flights on a periodic basis. We're actually scanning our transmission circuits and we're building a hazard tree risk model to specifically target area or identify areas that we have risk with a tree -- with a potential tree falling.

So the red polygon areas you can see in the picture here, these are actually called threat areas. And this is our tree canopy risk model. Once we have our threat areas built from the scanning, we have our subject matter experts review the right-of-ways and determine if further action is needed. In most cases, the -- if further action is needed, we go remove the tree. The tree may be particularly tall or particularly wide, and the scanning technology actually determines if this tree falls based on the location of the center line of the conductor and where the tree is, if it will impact the transmission line or not. So we're specifically targeting these trees that will impact a transmission line upon failure and upon falling into the right-of-way from outside the right-of-way.

The work executed, again, under this project is really looking at not just trees that are -- that are unhealthy or that are already leaning, but it is looking at any tree that could potentially cause a problem on that transmission circuit.

A specific location that I'll mention here for this project areas are Harris Plant to Siler City 230-kV. Before I get into that, I will mention another similarity to Mr. Guyton's discussion. The hazard tree removal or vegetation management project does not have a quantitative cost-benefit analysis. It's a qualitative analysis. And for the same reasoning we see this as an obligation to serve our customers. We are -- this is a necessary program area that we've executed for some time.

The Harris Plant Siler City 230-kV line south of Raleigh here. This is a 33-mile line connecting the Harris Nuclear Plant approximately 1,000 MW generating station to three different substations, four different transformer banks. This serves approximately 20,000 customers. This is a 100-foot right-of-way.

Our scanning which is using a lidar technology. It's a type of scan. We are identifying threats up to 30 feet outside of that right-of-way. And then we're proactively targeting removal of those trees that have been deemed to be threats and falling risks for that transmission line.

For transmission-specific outages, about 25 percent of customer minutes interrupted are from trees from outside the right-of-way. So one-quarter of all customer outages that emanate from the transmission system are coming from trees outside of the right-of-way, so it's a very significant project for us for customer reliability.

I'll move next into our circuit breaker upgrade project. This upgrade project is targeting assets that are at the end of life. Particularly, we're targeting oil circuit breakers. Oil-filled circuit breakers are a legacy technology. It is an oil-filled tank. That oil actually arrests the fault and the arc gases, and it extinguishes the arc when a circuit breaker opens or closes.

It's an outdated technology and these breakers are prone to failure. Our strategy here is identify assets that are beyond the end of useful life that have a expectation for failure based on make, model, trending, that we have based on the number of operations and the number of faults. That's data we gather. Essentially, the more a breaker operates the more wear it is getting.

We also are targeting locations based on the number of customers served, the configuration. Is it networked? In other words, is there redundancy or is it a radial system? There is no redundancy built in.

So we're taking all these inputs, we're targeting the locations, and then we're replacing that oil circuit breaker with an upgraded technology. We're using vacuum circuit breakers. It's a vacuum chamber that extinguishes or prevents an arc from occurring for distribution level voltages, so that would be transmission -- the assets in a transmission substation less than 44-kV. And then for the higher voltage assets we're using pressurized gas breakers, which is the state-of-the-art modern standard for fault interruption at the transmission level.

And again, as we upgrade those assets, we're installing upgraded protection and control relays, digital relays that can get us that additional information for remote monitoring and control of the grid.

One important factor with circuit breakers is, and I alluded to this earlier, if a circuit breaker does not operate reliably, that is to isolate a fault, the section of the transmission grid that isolates grows, right, the backup breakers need to operate. So this could be at remote substations further out on transmission lines at adjacent transmission stations and, therefore, more customers are interrupted. So getting a circuit breaker -- ensuring a circuit breaker reliably operates the fault when given a signal to open is very important to minimize the impacts on our customers.

Every time a circuit breaker fails and -- when a -- I'll say too then. When a fault occurs and particularly when a circuit breaker fails to open, in addition to that, that direct failure for the customer served on that line, we're also getting a voltage sag on the system. So this is the same for a transformer failure as well. These failures do result in significant voltage sags that impact our sensitive industrial customers and manufacturing customers, so it's our goal to prevent those impacts and proactively address these assets.

This specific project location, the Milburnie 230-kV substation supports the greater Raleigh area. This is east of Raleigh. And we are targeting the replacement of five 115-kV circuit breakers. You can see a picture on the lower right of what these oil circuit breakers look like.

This specific station I mentioned is very critical, so five different lines come into this station. Those lines go out to serve 77,000 customers. In this specific station, we actually had a recent outage event where one of the breakers did fail to operate in the required clearing time and breakers further out opened. We directly impacted 17,000 customers on that one outage event, so a single fault on the transmission system and 17,000 customers impacted. So that type of event is exactly what we're looking to avoid and eliminate will greatly reduce the impacts of during while executing this project.

Transformer upgrades, again, some parallels to breakers. I mentioned earlier our transformers transform voltage from transmission levels to other transmission levels, so 500-kV to

230, 230 to 115. That's for connecting out to the various levels of the transmission system for bulk power flow. And then they also transmit or transform voltage from the 230-kV to 115-kV system down to the 24-kV system commonly in the DEP area. So these are critical assets for serving our customers.

What we're doing is, again, we're targeting specific transformers that are at end of life. We're using field inspections, visual inspections, electrical testing. We're using make, model information, trending information, vendor, and industry data to select what assets are prioritized for replacement. We're scoring those projects, again, using the model that I talked about earlier on based on that specific location, the number of customers served, the voltage level, et cetera.

This project also includes regulators. Regulators are -- substation regulators specifically are very similar to transformers. One moment. Whereas transformers transform voltage over large areas, regulators control voltage over a very tight band, so plus or minus one volt in some cases. And we are obligated to maintain this voltage out on our systems. And you heard a little bit about voltage regulation earlier from Mr. Guyton. A regulator in a transmission substation controls the voltage for all the circuits leaving that station. And we'll look at an example of that on the next slide.

One of the keys things this project eliminates is a vulnerable arc-in-oil design for load tap changers. As we see more and more renewable energy resources and particularly variable energy resources connect to the grid, this arc-in-oil technology is a specific vulnerability.

But essentially it's an oil tank where, again, similar to a breaker, as a voltage regulator or a transformer controls voltage, there's an oil tank where this arcing occurs. Gases can accumulate in that oil tank over time and lead to catastrophic failure.

When a transformer or a regulator fails catastrophically, there's often release of oil. There is often collateral damage due to the size of this equipment and the amount of energy that's stored in there and the amount of oil that's stored in there. So in addition to just that asset replacement cost, the collateral damage and the impacts of the equipment adjacent to it in a substation can be very significant from a cost standpoint and also from a time standpoint for recovering from that outage event.

So again, these are reasons why we want to proactively address these assets that are at end of life, replace them prior to failure, prior to the customer being impacted, and prior to the grid being impacted by that failure.

New designs use a vacuum load tap changer that eliminates this vulnerable technology, again, particularly susceptible to when we have variable energy resources and we have a lot of voltage regulations as we see cloud-cover changes.

The specific example or project location I'll speak to for our transformer upgrade project is the Wilmington-Ogden 230-kV three-phase regulator replacement. This is in the Wilmington, North Carolina area. We are replacing a three-phase stations regulator. This one regulator provides voltage control for four different distribution circuits leaving that station. Those circuits serve over 8,500 customers.

The last thing I'll mention here is

three-phase regulators are the top outage cause category for substation equipment failures in DEP for, again, outages emanating from the transmission system. When we look at substation equipment, we've had over 11 million customer minutes interrupted in the last five years. So it's very important for us to target these assets, upgrade these assets with non or with designs that are less vulnerable to these failures.

Going to move onto the last project area, which is our capacity and customer planning project area.

This type of work is very critical to meet the capacity needs of our customers. I mentioned earlier our interrelationships in working between our customer delivery planners, our generation planners, and our transmission planners making sure we can project the needs for growing and shifting customer demands in our territory.

In addition to this, we have an obligation to meet our NERC compliance requirements and this includes modeling the transmission system under certain failure scenarios. Because the transmission system can impact so many customers upon a single failure, we have compliance obligations to plan for a single failure scenario and plan for different scenarios that may impact the grid. So if we lose certain equipment, what's the result and impact? Will it result in overloads? Will it result in cascading outages? You know, impacts that go much beyond one substation to larger areas of the grid.

So this area, this project area is all about mitigating those impacts and planning for those future potential consequences to the grid.

I mentioned earlier these capacity projects are informed through the ISOP process, so we are screening capacity upgrades for non-wires alternatives such as battery storage and we are moving forward with the best option from a cost-benefit perspective approach.

I'll talk again about our transmission expansion plan, aka our red zone projects and go into a little bit more detail here.

We have 11 projects that are targeting capacity upgrades in our territory. Again, these red zones are areas where we have maximum solar viability and we have minimum capacity. We feel it's truly important to transform the grid to this

-- to the clean-energy future and upgrading these lines is really a key part of that transformation for us.

The many interconnection studies over many years have identified the need to upgrade these circuits and have proven the need.

We are also processing these projects through the North Carolina Transmission Planning Committee and the Transmission Advisory Group specifically to obtain shareholder input.

The Transmission Planning Committee Oversight Steering Committee will ultimately have to approve these projects and this is all in line with FERC requirements for transmission additions.

These projects are an important part and not just form the energy perspective, but also important part of our plan from reliability perspective. We're delivering significant reliability benefits and we're also evaluating these projects under a traditional benefit-to-cost reliability model, as we do our other projects. We are looking at the conductor replacement, the structure replacement, and the mitigating impacts of, you know, preventing failures due to upgrading that equipment.

We do understand additional discussion on these projects is ongoing with carbon plan proceedings.

One specific project location I'd like to discuss is the Craggy Anka Capacity Project. And this project, you can see on the picture on the right side the north and south parts of it, is the general Asheville area. You can see the yellow line, that's an existing 230-kV transmission circuit.

Conspicuously in the middle, there is no 230-kV circuit between the Craggy and the Anka substation, so we're missing this corridor kind of in the central Asheville area here or to the west side where we are limited at how much power we can transmit between the different parts of the system.

And our planning models have actually identified a potential load shed outage scenario by the winter of 2025 based on limited ability to move bulk amounts of power between the system. So we're building a 230 volt connector line between these two points. And we're doing that in a least impact way as possible. We're using an existing 115-kV right-of-way that spans between these two stations. You can see an artist rendering in the lower left-hand side of the picture where we're actually going to be putting the existing 115-kV circuit rebuild on one side of the structures and the new 230-kV line on the other side of the structures.

So I mentioned the benefit. Directly this project serves approximately 30,000 existing customers from this line and in the greater Asheville area, much larger number of customers for general voltage stability and grid stability in the greater area.

Okay. And the last slide will be our closing remarks. Justin?

MR. BROWN: If you want to click the last slide. I just want to say, you know, we've certainly provided a lot of information today and in our prefiling materials that we did. We believe the projects today for both transmission and distribution compliment each other in supporting the clean energy transition in North Carolina really to build a grid that has -- can accommodate two-way power flow that has increased automation, overall situational awareness for the grid, and really postures us overall for increased reliability and resiliency overall for the system. Certainly postures us for a safe expansion of renewable generation and distributed energy resources at the edge of the grid along with providing equitable benefits for customers across the entire system done in an affordable way.

Thank you for your time today.

CHAIR MITCHELL: All right. Thank you all. Let me check and see if there are questions from the Commissioners. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: This is a general question that speaks to both components, if you're able to do so and, secondly, if you're willing to do so, and I understand both conditions have to be met, can you forecast whether any portions of these proposed projects will be associated with a performance incentive metric in the upcoming rate case? Are they going to be tied to a performance metric?

MR. BROWN: So I do believe that performance incentive metrics are a required component of an MYRP filing.

COMMISSIONER CLODFELTER: They are, but

you only have to propose one out of a basket of several you could propose, and I'm just trying to find out whether this one might be one of the ones you're going to propose.

MR. BROWN: When you say "this one"?

COMMISSIONER CLODFELTER: Associated with your distribution and transmission projects. Are you going to propose any performance incentive metrics to measure your success or failure?

MR. BROWN: I do know that there will be at least one, but I don't know if they are specifically tied to these projects.

COMMISSIONER CLODFELTER: Don't know if it's going to be associated with these projects. That's all right. As I say, you might not know, but even if you know you might not be willing to say today, but I thought I'd ask the question to see. All right. Thank you.

CHAIR MITCHELL: All right. Additional questions for DEP? I see Commissioner Duffley. Your hand is up.

COMMISSIONER DUFFLEY: Yes, thank you. So going to slide 40, you were talking about new delivery points for customers. And so my question is which type of customers? Are you speaking of retail customers or wholesale customers? And then if you're speaking of retail customers, are you speaking of residential, commercial, or industrial?

MR. BROWN: Sure. Thank you for the question. Generally, industrial customers would be the new customers that the transmission portfolio would sponsor projects for. That would be new industrial customers directly connected in the transmission system. The retail projects would typically come through sponsorship of the customer delivery distribution arm.

COMMISSIONER DUFFLEY: Okay. Thank you for that clarification. And then on page 42, you were discussing the reduction of faults. I just would like a sense of how many faults the transmission system sees per year.

MR. BROWN: Sure. You know, it can vary widely, particularly during storm scenarios. If we look at sustained faults, sustained number of outages, year to year it can vary from 50 to 100 outages. That's not uncommon. The average over the past five years is approximately in the 70 range for sustained faults. Momentary is significantly higher than that. The transmission system is built with reclosing capability on the circuits, so many hundreds of faults obviously occurring on the transmission system when you look at momentaries on an annual basis.

COMMISSIONER DUFFLEY: Okay. Thank you for that. I don't have any further questions.

CHAIR MITCHELL: All right. Just I would like to follow up on the response there. So a momentary fault, does that result in a disruption of service to customers or is it -- can you help me understand what that means in practical terms?

MR. BROWN: Yes. Good clarifying question. A momentary fault is a fault that interrupts customers that lasts for on the transmission system one minute or less. So a fault that occurs for 59 seconds would be a momentary. One minute or more would be a sustained outage. So it's certainly an impact that customers would notice, particularly for those commercial and industrial customers can be consequential, even at the momentary level.

CHAIR MITCHELL: Okay. Thank you. All right. Commissioner Clodfelter?

COMMISSIONER CLODFELTER: I'm going to be asking a question. You may not have it there in front of you but the question really comes from Exhibit TC-9C. And I really just want to understand what that exhibit is telling me.

So these are the capacity and customer planning projects. And there's a table showing the costs, the operational benefits, the customer benefits, and the combined cost and benefits and I follow the chart through the cumulative net benefit turns positive starting in 2035 and in later years out, so it's a upfront investment that you recover over an extended period of time.

What I really want to understand is the line under customer benefits that's titled "residential/commercial/et cetera customers". So, I mean, you've got a line above that which is the customer outage benefits, so I assume that that second line, residential/commercial/kcustomers really doesn't include a lot of outage benefits or traditional reliability benefits. It's including something else there. And what is that? Is that load growth? If it's not load growth, a lot of these projects as you've already said are red-zone projects that are increase system capacity to absorb additional renewables. And so how does that translate into the number that's shown on that line of customer benefits? Is that -- are those societal benefits?

MR. BROWN: So I am looking at that exhibit and what I'm seeing here is actually the avoided customer sustained outage benefits residential/commercial/et cetera customers is all one row. And then the total --

COMMISSIONER CLODFELTER: Oh, it's not two rows?

MR. BROWN: No.

COMMISSIONER CLODFELTER: That's not two rows. It's a single row.

MR. BROWN: That is correct. That is correct.

COMMISSIONER CLODFELTER: Caught me. You caught me on that. So that number then does include the value of outage -- outages avoided and the cost of outages avoided.

MR. BROWN: Yes, sir. That's correct. That is using the ICE model. The societal benefits in terms of avoided outage, in terms of avoided outage cost.

COMMISSIONER CLODFELTER: Sure. But in terms of, for example, the projects that are on the list on page 5 there, a lot of which are the red-zone projects, I've begun to recognize them by now individual projects, to the extent those are enabling retirement of carbon resources and substitution of renewable resources. Are those -- is that substitution being valued in your cost-benefit analysis? And if so, how is it being valued?

MR. BROWN: At this point, those benefits are not being valued quantitatively.

COMMISSIONER CLODFELTER: So then on this TC-9C, that line that we just looked at which you've now explained to me is a single line not two lines, does not include the benefits from the enabled conversion from fossil to carbon-free resources?

MR. BROWN: That is correct. Yeah. Of course there is --

COMMISSIONER CLODFELTER: Thank you, sir.

MR. BROWN: -- difficulty in quantifying that. We are -- it's certainly something that we are interested in in the future.

COMMISSIONER CLODFELTER: We're all interested in it. I just wanted to figure out if you had found a way to quantify it and put it on this page. That's what I was trying to find out. Thank you.

MR. BROWN: You're welcome.

CHAIR MITCHELL: While you're looking at TC-9C, page 5 of 5 of that exhibit, can you just point me to the 11 projects that are in the red zone? And I'm wondering if they're located on that page 5 of 5. And if not, where would I find them?

MR. BROWN: Sure. You can -- they are listed -- let's get to that page. We don't have them uniquely called out as a sub -- as subprojects --

CHAIR MITCHELL: Right.

MR. BROWN: -- within here. Now, they are also listed -- I'm going to go to a different exhibit because I have them more easily marked up, and the Technical Conference MYRP Project Details and Transmission Exhibit -- I don't have the number right here -- but they are listed in there. I can go through the titles of the locations if you'd like them or we can provide that in follow-up.

CHAIR MITCHELL: Just provide it in follow up; that would be helpful.

MR. BROWN: Okay. Thank you.

CHAIR MITCHELL: And just to make sure, because I think I missed that, the exhibit you were just referencing, is it TC-7?

MR. BROWN: Yeah. Make sure I -- yes, that's correct.

CHAIR MITCHELL: Okay. All right.

MR. BROWN: TC-7, yes.

CHAIR MITCHELL: Okay. Thank you. While I have the mic, I'm going to ask you one more question about the ICE calculator. I've heard you reference it now several times and we talked about it during the discussion on the distribution programs. And you mentioned that you-all have a third-party model that you-all are using that incorporates the ICE calculator.

So is the ICE calculator model being used the same way for the transmission side as it is for the distribution side? Okay.

MR. BROWN: It is very similar. I will say we are using DEP-specific information fed into that SAVe and SAFe variables and retail customer class mix, or residential small C&I, large C&I, is not exactly the same, so we are -- we have that calculator and table embedded in the software. The software then does that calculation. But from my knowledge and working discussions with my peers, customer delivery is utilizing the tables very similarly.

CHAIR MITCHELL: Okay. I recognize that benefits associated with investments in the distribution system and benefits associated with investments in the transmission system may be different, but to the extent you're looking at a same or similar benefit, are they being calculated in the same way?

MR. BROWN: Think about that. Yeah. So for an avoided outage we would calculate the benefit the same way.

CHAIR MITCHELL: Okay. That's -- thank you. That's helpful to me. That's a good example. Okay.

Let's see, let me see if Commissioner Brown-Bland has a question.

COMMISSIONER BROWN-BLAND: Yes, I do have a question. With regard to your discussion about the right-of-way, working the right-of-way, and you gave an example where you're clearing 30 feet outside of the right-of-way, is that work -- is that to comply with any standard like a NERC standard or does it exceed any required standard?

MR. BROWN: Yes. Thank you for the question. We do have NERC compliance obligations to implement a vegetation management program specifically for our 230-kV system, 200-kV and above. It does not specifically dictate distance outside of right-of-way, but we are obligated to have a program and to demonstrate how we are preventing trees from encroaching upon our minimum vegetation clearance distance. So we are going above and beyond those minimum compliance requirements from a reliability perspective.

COMMISSIONER BROWN-BLAND: Based on the work that you've done so far, you know, in examining all of that, is 30 foot kind of expected to be the Company standard or would we expect to see this change over time? Like would it expand to 35 or 40 feet out?

MR. BROWN: I am not a vegetation management expert, so I couldn't weigh in on that.

I'm not sure the answer there.

COMMISSIONER BROWN-BLAND: Okay. Thank you.

CHAIR MITCHELL: Okay. We're at five o'clock and I'm going to check in with the court reporter to see how she is doing and if she can continue on.

COURT REPORTER: [Nods in agreement]

Okay. So since we are close to the end of the presentation from Duke, I'd like to continue. It's my understanding we have one interested party that intends to present. Counsel, I'm looking at you to confirm that.

MS. CRESS: Yes, Chair Mitchell.

CHAIR MITCHELL: Okay.

MS. CRESS: CIGFUR has a presentation.

CHAIR MITCHELL: Okay. So we will push on then and finish up today unless someone raises a strenuous objection.

(No response)

Okay. All right. Well, let's continue on with questions from Commissioners. Commissioner Hughes, do you have any questions? And then we'll hear from McKissick and then Kemerait.

COMMISSIONER DUFFLEY: Commissioner Hughes, you're on mute.

CHAIR MITCHELL: All right. Commissioner Hughes, we cannot hear you. All right. Let's hear from --

COMMISSIONER HUGHES: Is that better?

CHAIR MITCHELL: We can hear you now. Go ahead.

COMMISSIONER HUGHES: The three objectives that you laid out at the beginning of and then again at the end were resiliency, expanded renewables, and DERs, and you have this equitable assets to benefits. We spent a lot of the day talking -- it seems to me talking about the first two, a lot of the modeling that went in, a lot of the technical details. Could you just talk briefly about what process you did for that third objective and was there any quantitative modeling for that third objective and kind of making tradeoffs and things?

MR. BROWN: Thank you. There's -- I would say that the equitable access to benefits is not really in a quantifiable way. Part of what we're doing when we looked across the distribution and transmission system is making sure that we didn't concentrate necessarily investments or types of investments in one particular area. They're intended to be broad across the DEP service territory, so that when new technologies do become available, that all customers on the system can take advantage of those.

And specifically too as Brent and Dan mentioned, by grouping the projects together in a localized area, we believe we're trying to ring the value of the resources that we have on the system, typically labor resources as well as materials, ring the biggest value out of those implementations so that we can have a eye on affordability overall for the customer.

COMMISSIONER HUGHES: And so it's mainly affordability?

MR. BROWN: Affordability and making sure that the investments aren't necessarily concentrated in one particular area of the system.

COMMISSIONER HUGHES: Okay.

MR. BROWN: Their broad nature.

COMMISSIONER HUGHES: Thank you.

MR. BROWN: You're welcome.

CHAIR MITCHELL: All right. Commissioner

McKissick?

COMMISSIONER McKISSICK: In the interest of time, this is a pretty quick question. It kind of follows up on one that Chair Mitchell asked about, the 11 projects in the red zone. First, how do you determine which of those to proceed with in this particular proposal that's before -- that will be, you know, submitted to us soon?

And then secondly, as I recall and my recollections may be mistaken, there were I think 13 projects in the DEP territory in the red zone. Was there consideration given to just knocking them all out considering the need to meet that capacity, you know, as expeditiously as possible?

MR. BROWN: Yes. I'll say the number of projects has shifted and shaped some as we continue to sort of most effectively bundle and combine. One project also moved to now it's a need under our transmission additions plan based on capacity changes. So it's moving -- it's a little bit fluid and that may be the difference between the 13, the 11.

These really are the bulk of projects as we see as the priorities now to upgrade. So there may be additional expansion-led projects in the future, but these are the projects that we see over the next three years in the time period of the multi-year rate plan, critical projects to implement the capacity upgrades on.

COMMISSIONER McKISSICK: Thank you. I guess the thing I would ask as you continue to work on this proposal is perhaps evaluating all of them, you know, and moving forward with all of them if it can logically be sequentially performed and executed in a way that's, you know, cost effective that makes sense, because there's a real need to address these red-zone areas as expeditiously as possible.

MR. BROWN: Thank you.

COMMISSIONER McKISSICK: Thank you.

COMMISSIONER KEMERAIT: To follow up on a couple of questions from Chair Mitchell and Commissioner Clodfelter about the red-zone upgrades, on page 55, the benefit-cost ratio for the red-zone upgrades and the additional part of the program is 1.6, which I think is the lowest ratio of any of the programs. Can you just briefly explain why this is included in your program since it has the lowest ratio of what you're proposing?

MR. BROWN: Sure. I'll expand on the benefit-to-cost ratio for our capacitor customer planning.

I recall this project area actually includes the red zone for transmission expansion projects, also includes the compliance of obligated compliance projects for reliability, NERC reliability planning and new customer connections specifically industrial customers connecting to the transmission system.

Compliance obligations, we do not actually score through a benefit-to-cost process. Because they are requirements under federal standards and rules, we do include the cost of those projects. We do not include the benefits. We skip the scoring. And they are, you know, obligations to implement.

So that does drive the benefit-to-cost ratio overall for this bundle of the project area lower than some of the other areas.

COMMISSIONER KEMERAIT: Thank you.

MR. BROWN: You're welcome.

CHAIR MITCHELL: Just following up there to make sure I'm clear. When you say compliance, you mean compliance with --

MR. BROWN: NERC standards.

CHAIR MITCHELL: -- with NERC standards? Okay. Okay.

COMMISSIONER KEMERAIT: And do you have the ratio for just the benefit/cost ratio for the red-zone upgrades themselves? Has that been differentiated or separated?

MR. BROWN: We have not to this point differentiated that.

COMMISSIONER KEMERAIT: Thank you.

MR. BROWN: You're welcome.

CHAIR MITCHELL: Go ahead.

COMMISSIONER CLODFELTER: The biggest bang for the buck that you've got on the list here is the Rockingham station uprate for the 500-kV uprate. What's involved in an uprate? How do -- I mean, for less than a million dollars you get a $108 million worth of a benefit; you get almost 15 percent of your total benefit for less than a million dollars. What's involved in a station uprate?

MR. BROWN: And that -- can you restate the project please?

COMMISSIONER CLODFELTER: It's the Richmond 500-kV Substation Uprate.

MR. BROWN: Okay. Okay. When we look at an uprate solution, there's multiple different things it could be. Obviously, the most expensive are rebuilding a line. In this case, although I'm not specifically familiar with the scope offhand, generally an uprate in a station is replacement of a limiting component from a current carrying equipment perspective. It could be a wave trap, which is a device that, you know, is used in current limiting or communication-related device that carries current. It could be a smaller-type asset within a station. Generally, the more favorable from a benefit cost perspective or lower cost operates our substation equipment operates.

Also relay settings. Surprisingly, sometimes we are restricted purely by settings on protective relays. So by changing those relay settings sometimes in conjunction with replacing a current transformer or a voltage transformer, we can actually uprate the overall rating of the facility which would be the station and the connected lines.

COMMISSIONER McKISSICK: Thanks for the education.

MR. BROWN: You're welcome.

CHAIR MITCHELL: All right. Let me check and see if there are any additional questions for the DEP panel before we let them go.

(No response)

All right. Well, thank you-all very much for your presentation today. We appreciate your being here with us and the explanations you've provided.

MR. BROWN: Thank you.

CHAIR MITCHELL: All right. Mr. Jeffries, if you would, we would like a follow-up filing on the TC-7 identifying the projects there.

MR. JEFFRIES: We've got those, that noted --

CHAIR MITCHELL: Okay.

MR. JEFFRIES: -- Chair Mitchell.

CHAIR MITCHELL: Thank you, sir. All right. You all may step down. Thank you.

MR. BROWN: Thank you.

CHAIR MITCHELL: All right. Ms. Cress, it's my understanding CIGFUR II has a witness who you all would like to call.

MS. CRESS: Yes, Chair Mitchell. Thank you. And I'll just note at the outset that we only learned moments before this Technical Conference began that we would be the only party making a presentation, but since our witness is here from Missouri, we are going to go ahead with our presentation and we appreciate the opportunity to do so.

CHAIR MITCHELL: Okay. Absolutely.

MS. CRESS: So with that, I'll turn it over to Bob Stephens with Brubaker and Associates. Thank you.

MR. STEPHENS: Good afternoon, Chair. Can you hear me okay?

MR. STEPHENS: Yeah.

CHAIR MITCHELL: We can hear you.

MR. STEPHENS: Good afternoon, Chair Mitchell and Commissioners. I don't know if my -- there is my presentation. All right.

You're all new to me and I'm new to you. I'm Bob Stephens. I'm with the firm Brubaker and Associates here on behalf of CIGFUR, the -- I'm sorry -- Carolina Industrial Group For Fair Utility Rates.

Those are my qualifications. I won't go through them in the interest of time. I'll just note a couple. I've been in the consulting industry regulated -- regulatory consulting and consulting the individual customers on electric rate matters for nearly 25 years. Before that I worked at the Illinois Commerce Commission and before that a utility.

I will skip over this page. You know what the mega trends are. We've already covered that. Here, I'd like to talk about what are priorities for CIGFUR. We're talking about billions of dollars of spend here, and it's true that there will need to be additional transmission distribution investments. There's no question about that. But from industrial customers' point of view, it's going to be imperative that we manage the cost of service because right now competitively priced service in North Carolina at a high level of reliability is helping to drive the industrial economy which helps drive the overall economy. So we ask that the cost of service be managed and the rate changes be as gradual as are feasible.

We encourage DEP to develop capital projects at least cost considering all options, transmission, production, and distribution, not siloing into one. And we've gotten some indication earlier today that they don't necessarily do that in all cases, but we want to encourage as much coordination there as feasible. And we want to encourage capital budget timing such that rate base doesn't grow in leaps and bounds suddenly.

DEP has identified billions of dollars' worth of costs here. Approximately three billion by my count based on the presentation. So we want to make sure that capital spend is conducted and deliberate in a gradual way.

And then finally, as part of the multi-rate plans, there will be tariff rates proposed and we want to make sure that those are set rationally, that they help encourage conservation among customers by efficient price signals, and that they reflect cost of service.

Regarding T&D service quality, it's important that we've heard several options for both supply and demand reliability. We want to make sure that the demand side is exhausted because customers can provide interruptible capacity that can help alleviate some of the stresses on both the transmission and distribution systems.

We want to ensure that power quality is maintained and at a least cost. You've heard talk today about voltage stability. For industrial customers, even small or even very momentary changes in voltage can have a detrimental impact. Sag, surges, transient changes generally under voltage that can all affect equipment and production. In fact, voltage sags even momentary can shut down industrial plants. They can damage equipment. And when that happens, you have lost production, you have in some cases the inability to meet customers' needs. So it's very important to maintain adequate voltage stability as well as frequency.

And then similarly SAVe and SAFe and CAIDe (spelling uncertain) are all valid measures, but you heard some discussion by Mr. Maley about what's a momentary outage. Momentary are the ones below one minute. For industrial customers harm can happen within a second. So we should consider another measure M-A-I-F-I, MAIFI, Momentary Average Interruption Frequency Index, which is the total of the momentary outages in the year divided by the number of customers.

Regarding tariff rates and efficient

consumption, we want efficient rates. We want fair rates. For the transmission service, cost should be allocated based on coincident demands. For distribution service at the circuit level, non-coincident demands are typically used taking into account customer density and circuit miles is an important factor as well.

When prices are efficient, they provide an economic incentive to customers to conserve. For example, if you set your demand rates too high and your energy rates too low, customers will get the wrong signal thinking that their demands don't cause cost on the system to the extent they do and, likewise, if their energy costs more. The most efficient functioning of a utility is when the prices reflect cost, so the customers can respond accordingly.

So I've covered a few things. Here are the key takeaways. The importance of gradualism and avoiding rate shock. We'd like for DEP to be able to show that system reliability benefits exceed the cost of the planned capital -- T&D capital spending. Indications so far are that they do, but we haven't dug into the numbers yet and that will be a part of the filing once made.

Delivery voltage should be aligned with embedded cost. If you're taking service at 230-kV, you don't use any distribution assets and, therefore, you shouldn't be charged cost of the distribution system, including these distribution improvements.

DEP covered the fact that the federal funds are being used. We encourage the Commission to make sure those funds are maximized.

And then finally, look at things beyond just SAVe and SAFe for measures of reliability to get to the important momentary interruptions as well.

We look forward to digging into DEP's filing once it's made. And with that, if you have any questions, I'll do my best to answer.

CHAIR MITCHELL: All right. Thank you, sir. Let me check in with Commissioners to see if there are questions for you. Any questions from Commissioners Brown-Bland, Duffley, or Hughes?

(No response)

I'm not seeing any. Well, thank you very much, sir, for your comments today. You may step down.

MR. STEPHENS: Thank you.

CHAIR MITCHELL: All right. And with that, we've come to the end of our day. Thank you, again, to all the presenters and for sharing this information with us. And with that, we'll be adjourned. Thank you.

(The technical conference was adjourned)

C E R T I F I C A T E

I, KIM T. MITCHELL, do hereby certify that the proceedings in the above-captioned matter were taken before me, that I did report in stenographic shorthand the proceedings set forth herein, and the foregoing proceedings were therefore reduced to typewritten format by me or under my direction.

Kim T. Mitchell
Kim T. Mitchell