ERRATA

To: Kimberley A. Campbell, Chief Clerk

From: Kim Mitchell, Court Reporter

CC:

Date: December 2, 2020

Re: Duke Energy Progress, LLC

Docket Number E-2, Sub 1219, Volume 15

The prefiled testimony and exhibits of Dennis Stephens was not included in Transcript Volume 15; therefore, I am attaching Mr. Stephens' prefiled direct testimony consisting of 46 pages as well as Stephens Exhibits 1 through 10, appropriately marked for the record.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-2, SUB 1219

	)	**TESTIMONY OF DENNIS**
	)	**STEPHENS ON BEHALF OF THE**
In the Matter of:	)	**NORTH CAROLINA JUSTICE**
Application of Duke Energy Progress ,	)	**CENTER, NORTH CAROLINA**
LLC for Adjustment of Rates and	)	**HOUSING COALITION, NATURAL**
Charges Applicable to Electric Service	)	**RESOURCES DEFENSE COUNCIL**
in North Carolina	)	**AND SOUTHERN ALLIANCE FOR**
	)	**CLEAN ENERGY AND THE**
	)	**NORTH CAROLINA**
	)	**SUSTAINABLE ENERGY**
	)	**ASSOCIATION**

Wired Group

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April 13, 2020

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EXHIBITS

Stephens Exhibit 1: Curriculum Vitae of Dennis Stephens.

Stephens Exhibit 2: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 5-4, Docket E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 3: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 4-6, Docket E-7, Sub 1214, January 21, 2020.

Stephens Exhibit 4: Duke Energy Carolinas Response to NC Sustainable Energy Association, Data Request Data Request 3-32, E-7, Sub 1214, January 2, 2020

Stephens Exhibit 5: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 5-33, Docket E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 6: Duke Energy Progress Response to North Carolina Justice Center, et al., Data Request 6-4, Docket E-2, Sub 1219, March 3, 2020.

Stephens Exhibit 7: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 8-34, Docket E-7, Sub 1214, February 10, 2020.

Stephens Exhibit 8: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 5-40, E-7, Sub 1214, January 27, 2020.

Stephens Exhibit 9: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 2-4, Docket E-7, Sub 1214, January 9, 2020.

Stephens Exhibit 10: Duke Energy Carolinas Response to North Carolina Justice Center, et al., Data Request 2-19, Docket E-7, Sub 1214, November 25 2019.

I. Introduction

Q. PLEASE STATE YOUR FULL NAME AND BUSINESS ADDRESS.

A. My name is Dennis Stephens. My business address is 1153 Bergen Parkway, Ste 130, Evergreen, Colorado, 80439.

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

A. I am an independent consultant. I collaborate frequently with Paul Alvarez, who is also testifying in this docket, and his firm, the Wired Group, on behalf of clients in distribution utility regulatory proceedings on matters of electric distribution grid planning, investment, operations, reliability, and distributed energy resource accommodation.

Q. PLEASE DESCRIBE YOUR PROFESSIONAL AND EDUCATIONAL BACKGROUND.

A: After graduating from the University of Missouri with a bachelor's degree in Electrical Engineering, I began work for Xcel Energy (then Public Service Company of Colorado) as an electrical engineer in distribution operations. In a series of electrical engineering and management roles of increasing responsibility, I gained experience in distribution planning, operations, and asset management, and the innovative use of technology to assist with these functions. Positions I have held over the years have included Director, Electric and Gas Operations for the City and County of Denver Colorado; Director, Asset Strategy; and Director, Innovation and Smart Grid Investments.

In 2007, I was asked to lead parts of Xcel Energy's SmartGridCity™ demonstration project in Boulder, Colorado, the first of its kind at the time, covering 46,000 ratepayers. I developed the technical foundations for the project, including the development of all concepts presented to the Xcel Energy Executive Committee for project approval, and including the negotiations with technology vendors on their contributions to the project. As Director of Utility Innovations for Xcel Energy, I also worked with many software providers, including ABB, IBM, and Siemens, helping them develop their distribution automation ideas into practical software applications of value to grid owner/operators. I retired from Xcel Energy in 2011, and now consult for the Wired Group part-time.

Q HAVE YOU TESTIFIED PREVIOUSLY BEFORE THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I submitted testimony on Duke Energy's Grid Improvement Plan, covering both Duke Energy Carolinas ("DEC") and Duke Energy Progress ("DEP"), in Docket No. E-7, Sub 1214. Because the Grid Improvement Plan covers both Companies, my testimony herein is virtually identical to that testimony.

Q. HAVE YOU TESTIFIED BEFORE OTHER STATE UTILITY REGULATORY COMMISSIONS?

A. Yes. I have testified jointly with Witness Alvarez in three rate cases before the California Public Utilities Commission. I testified regarding the appropriateness of multi-billion-dollar grid modernization proposals by Southern California Edison and Pacific Gas and Electric. I also critiqued Indianapolis Power and Light's $1.2 billion Grid Improvement Plan before the Indiana Utility Regulatory Commission and testified jointly with Witness Alvarez in cases regarding distribution grid planning process development in Michigan and New Hampshire. I have also supported the Wired Group in client projects not involving testimony, including one in South Carolina regarding Duke Energy's Grid Modernization Plan,[1] and a similar paper on Dominion's Grid Transformation Plan.[2] (I note the Virginia SCC largely rejected Dominion's Grid Transformation Plan.)[3] My full CV is provided as Stephens Exhibit 1 to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am testifying on behalf of the North Carolina Justice Center, the North Carolina Housing Coalition, the Natural Resources Defense Council, and the Southern Alliance for Clean Energy (collectively, "NCJC et al.") and the North Carolina Sustainable Energy Association ("NCSEA"). My testimony critiques the Grid Improvement Plan ("GIP") and associated cost-benefit analyses DEP presents in this case.[4]

II. Preview and Recommendations

Q. PLEASE PROVIDE A PREVIEW OF YOUR TESTIMONY AND RECOMMENDATIONS IN THIS PROCEEDING.

A. My testimony begins with context, describing typical distribution planning processes utilities have employed for decades. I also provide historical data indicating that Duke Energy's reliability has deteriorated markedly in recent years despite grid investment growth far exceeding peak demand growth. My

[1] Alvarez P and Stephens D. *Modernizing The Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers*. Paper prepared for GridLab. Jan. 31, 2019.

[2] Alvarez P and Stephens D. Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. October 5, 2018.

[3] Final Order RE: Petition of Virginia Electric and Power Company. Virginia State Corporation Commission Docket No. PUR-2018-00100 (January 17, 2019).

[4] DEC and DEP have each filed the GIP in their concurrent respective rate cases. Since the GIP is, for the most part, common to both DEP and DEC and incorporates territory-overlapping programs and proposed investments, I will refer to DEC and DEP, collectively, as "Duke Energy" throughout my testimony in reference to the GIP proposal.

testimony then identifies multiple deficiencies in the design, technical justification, and cost-effectiveness of many GIP programs, and identifies a complete lack of justification for others. These illustrate the opportunity for a transparent, stakeholder-engaged distribution planning and capital budgeting process to improve the value delivered to North Carolina ratepayers, communities, and the environment by distribution grid investments.

Q. WHAT IS YOUR PRIMARY RECOMMENDATION TO THE COMMISSION?

A. My primary recommendation is for the Commission to reject Duke Energy's GIP and establish a proceeding to develop such a process for use in developing future distribution plans and capital budgets that better align the needs of stakeholders and utilities. Witness Alvarez's testimony provides an outline for such a process, and additional justification for the same recommendation.

Q. IN THE EVENT THAT THE COMMISSION DOES NOT ACCEPT YOUR PRIMARY RECOMMENDATION, DO YOU HAVE A SECONDARY RECOMMENDATION?

A. Yes. My testimony provides a secondary, alternative recommendation, wherein the Commission evaluates each GIP program independently. This part of my testimony examines individual GIP programs and sub-components in detail, providing valuable, objective information regarding the design and justification (or lack thereof) for each GIP program. I categorize GIP programs into groups of similar merit. In the event the Commission rejects my primary recommendation, I hope these "merit groupings" will serve as a set of secondary recommendations to inform Commission decisions. The merit groups and programs are presented in Table 1, summarized below, and explained in detail in my testimony.

Table 1: Summary of GIP Programs/Sub-components By Merit

Program/Subcomponent	Capital $ per Oliver Exh. 10 (in millions)	Suggested Adjustments	Capital $ per NCJC/NCSEA If GIP Not Rejected
Merits Approval w/Conditions	$ 374.16	$ -	$ 374.16
Integrated Volt/VAr Control	$ 216.66	$ -	$ 216.66
Transmission H&R -- Flood & Animal Mitigation Components	$ 13.18	$ -	$ 13.18
Long Duration Interruption/High Impact Sites	$ 27.10	$ -	$ 27.10
Enterprise Applications/ISOP Software/DER Software	$ 41.94	$ -	$ 41.94
Cyber and Physical Security, excluding substation physical	$ 23.04	$ -	$ 23.04
Enterprise Comm's excluding new data and voice networks	$ 52.24	$ -	$ 52.24
Merits Approval w/Material Modifications & Conditions	$ 843.05	$ (336.80)	$ 506.25
Self-Optimizing Grid/Advanced Dist Mgmt System	$ 722.48	$ (336.80)	$ 385.67
Transmission H&R (DER Capacity Upgrades ONLY)	$ 120.57	$ -	$ 120.57
Merits Rejection	$ 659.95	$ (659.95)	$ -
Targeted Undergrounding	$ 114.54	$ (114.54)	$ -
Distribution Transformer Retrofit	$ 118.02	$ (118.02)	$ -
Transfomer Bank Replacement	$ 116.39	$ (116.39)	$ -
Oil-Filled Breaker Replacement	$ 200.29	$ (200.29)	$ -
Substation Perimeter Security	$ 110.71	$ (110.71)	$ -
Merits Rejection Pending Further Evaluation	$ 440.27	$ (440.27)	$ -
Enterprise Comm's, new data & voice (tech/econ make/buy analyses)	$ 159.58	$ (159.58)	$ -
Distribution Automation (benefit-cost analysis)	$ 194.29	$ (194.29)	$ -
Transmission System Intelligence (benefit-cost analysis)	$ 86.41	$ (86.41)	$ -
GIP Components Being Considered in Other Dockets	$ 192.48	$ (192.48)	$ -
Energy Storage (NCUC #E-100, Sub 164)	$ 129.00	$ (129.00)	$ -
Electric Transportation (NCUC #E-2 Sub 1197 & E-7 Sub 1195)	$ 63.48	$ (63.48)	$ -
TOTALS	$ 2,509.92	$ (1,629.51)	$ 880.41

<u>Programs and sub-components that merit approval with conditions</u>. Some GIP programs merit approval with conditions. The mix of spending between and even within the programs and sub-components would likely be optimized through the use of a transparent, stakeholder-engaged distribution planning and capital

budgeting process. Programs that I believe merit approval with conditions, amounting to $374 million in capital, include (1) the Integrated Volt-VAR Control ("IVVC") program; (2) the flood and animal mitigation components of the Transmission Hardening and Restoration program; (3) the Long Duration Interruption/High Impact Sites program; (4) foundational software, including Enterprise Applications, Integrated System Operations Planning ("ISOP"), and Distributed Energy Resource ("DER") dispatch; (5) Cybersecurity (excluding substation physical security); and (6) Enterprise Communications (excluding mission critical voice and data network investments pending further evaluation, as described).

Self-Optimizing Grid. This program merits approval with conditions, but at a reduced investment level (from $722 million to $385 million) so as to focus the spending on the 50% of circuits and segments of highest priority/greatest benefit. This will improve the benefit-to-cost ratio of self-optimizing grid program capital and reduce the risk that the program is applied to circuits for which costs exceed benefits. Reliability performance can be measured so that informed consideration can be given to program expansion in the future. If the Commission approves this program, I also recommend it keep a very close eye on the $48 million advanced distribution management system deployment.

Transmission Hardening and Resilience (not related to flood or animal mitigation). My testimony explains why this capital budget ($120 million) merits approval with conditions but modifies the goal and design of the program completely. As proposed, the program makes progress towards greater accommodation of DER, but does not actually increase the capacity of Duke Energy's grid to accommodate more DER by a single watt. Instead, I recommend the portions of the GIP transmission hardening and restoration budget not targeted to flooding and animal risk mitigation be focused on increasing the capacity of Duke Energy's grid to accommodate more DER. These include (1) upgrading DEC's 44kV lines to 100kV lines; and/or (2) increasing the number of DEC substations served by 44kV lines; and/or (3) reducing any DER bottlenecks in DEP's transmission grid. The value of involving stakeholders in the optimization of the transmission hardening and restoration budget to maximize DER accommodation per dollar of GIP capital across the DEC and DEP transmission system is clear.

Programs to Reject Due to Lack of Cost-Effectiveness/Compliance with Standard Practice. My testimony explains why these programs are not cost effective and are not standard practice in the industry. Totaling $660 million, they include (1) targeted undergrounding; (2) distribution transformer retrofit; (3) transformer bank replacement; (4) oil-filled breaker replacement; and (5) physical substation security.

Programs to Reject Pending Further Evaluation. My testimony explains that insufficient information is available to make a recommendation on these programs. Witness Alvarez's testimony explains why a technical and economic make vs. buy analysis, considering recent and emerging public telecom network capabilities, is required before a recommendation regarding $160 million in new voice and data communications network investments can be determined. I also note that no benefit-cost analysis has been completed on distribution automation and transmission system intelligence programs and recommend that the Commission reject them until Duke Energy completes these analyses.

Q. PLEASE DESCRIBE THE CONDITIONS ON APPROVAL THAT YOU RECOMMEND.

A. I recommend the Commission apply three conditions for any GIP programs it approves. The first condition is ongoing performance measurement against pre-GIP baselines. I point specifically to measuring annual average voltage reductions from the IVVC program, as well as reliability improvements from the Self-Optimizing Grid program, but I believe a policy of performance measurement is important for any extraordinary distribution investments the Commission approves. There is no other way to determine if the program benefit claims Duke Energy makes are reasonable, or if the approved programs should be expanded or curtailed in the future.

The second of these conditions involve cost caps and associated operating audits. As indicated in Witness Alvarez's testimony, Duke Energy never actually provides a GIP capital budget limit or estimate of the cost to ratepayers. I recommend the Commission establish capital cost caps for every GIP program or sub-component it approves, as well as specifications for the program-specific extents of capabilities it expects to be operational within the cost cap (generally, as specified by Duke Energy in its GIP program descriptions and/or cost-benefit analyses). Without cost caps or extent specifications (circuits, line miles, substations, etc.), the Commission has no way of knowing whether promised capabilities or extents are operating for the proposed costs. Program audits will be needed to verify that capabilities have been implemented to the extent promised for the costs estimated. The Commission may also wish to act on my recommendation regarding financial consequences for exceeding program cost caps or failing to deliver the promised extent of a program's capability within a cost cap. As proposed, ratepayers bear all of these risks, and shareholders none of these risks. Cost sharing between ratepayers and shareholders for cost overruns or extent shortfalls would hold Duke Energy accountable for cost estimate accuracy and program implementation success.

The third condition relates to capital DEP spent on GIP assets placed into service during the test year. For the GIP programs the Commission approves, I recommend capital spent on GIP assets placed into service during the test year be included in program cost caps as a condition of approval. For the GIP programs the Commission rejects – and in particular, those programs it rejects due to a lack of cost-effectiveness and industry standard practice compliance – I recommend recovery of and on capital spent on such assets placed into service during the test year be denied.

Q. DO YOU HAVE OTHER RECOMMENDATIONS FOR THE COMMISSION REGARDING THE GIP?

A. Yes. My testimony indicates that many GIP programs are not cost-effective, and outside standard industry practice, and that Duke Energy provides no economic justification at all for other GIP programs. Witness Alvarez's testimony indicates that GIP program costs to ratepayers and communities are dramatically understated and ratepayer benefits dramatically overstated. In this rate case Duke Energy proposes deferral accounting treatment to address "regulatory lag" for GIP costs. This serves to increase the likelihood that Duke Energy will earn or exceed its authorized rate of return on equity, thereby increasing Duke Energy's already-adequate incentive to invest in its grid. I concur with Witness Alvarez's conclusion that deferral accounting treatment leads to excessive capital spending on sub-optimal projects, and with his recommendation that deferral accounting for GIP investments be rejected on that basis.

III. Historical Context

Q. BEFORE PROCEEDING, PLEASE PROVIDE THE HISTORICAL CONTEXT YOU MENTIONED.

A. Since the introduction of alternating current and the power grid concept in the early 20th century, utilities have taken a simple approach to grid planning. They build systems to deliver power from an energy source to a consumer. As the number, locations, and energy use of the consumers grew, utilities methodically planned and implemented expansions in grids' geographic extents and energy capacities over time. As grids developed, grid reliability and safety issues arose. A solution was devised, which was the use of substations as hubs for protection and control to deliver safe and reliable electricity to consumers via "spokes," which engineers know as circuits. Early grids were initially protected by fuses, which later evolved into oil-filled circuit breakers in conjunction with analog electromechanical relays, reclosers, and various devices to reduce circuits into individualized sections. These protection systems were designed to de-energize small sections of the grid, isolating faults and other problems to prevent damage to the rest of the grid, and became the standard for grid protection and control.

Q. HOW IS THIS HISTORICAL CONTEXT RELEVANT TO THIS PROCEEDING?

A. For over a century, utilities have successfully incorporated new technologies, along with new operating practices, to deliver safe, reliable, and low-cost electric distribution services under conditions of growing loads and increasing ratepayer expectations. Utilities have done so using a methodical, common-sense approach to distribution planning that focuses on a single question: do the benefits (i.e., reduction in risk of an adverse event such as a service interruption) justify the costs? Over the course of many decades, a generally-accepted distribution planning process, as well as a generally-accepted set of standard industry practices, has arisen. Both the planning process and the standard practices are the result of thousands of electrical engineers like me, asking this question thousands of times while working on thousands of distribution circuits.

Q. ARE YOU SUGGESTING THAT THERE IS NO NEED FOR INNOVATION IN DISTRIBUTION PLANNING AND INVESTMENT?

A. Not at all. While generally-accepted distribution planning processes and standard practices have proven their value and should not be abandoned, this does not mean they have not undergone, or should not undergo, adjustments from time to time. Duke Energy Witness Oliver identifies megatrends prompting the development of the GIP.[5] I condense these down into two that require at least

[5] *Direct Testimony of Jay W. Oliver*, ("*Oliver Direct*"), Exhibit 2, p. 2 (September 30, 2019).

some adaptation of utilities' historical distribution planning processes: (1) the increasing penetration of distributed energy resources ("DER"), which can lead to bi-directional power flow in high-enough capacities (towards the substation as well as away from it); and (2) increased frequency of severe weather events. However, I do not agree that these trends require a departure from best utility practices in distribution planning. Changes in DER adoption and weather severity simply require the application of new technology and practices on an as-needed basis, justified through the technical reviews and cost-risk evaluations that have always been a part of utility distribution planning processes. Stakeholders can and should be part of these reviews, evaluations, and decisions. I also do not agree that large investments in grid modernization require a change in the methods by which utilities are compensated.

Q. WHAT RELEVANCE DO YOUR CONTEXTUAL OBSERVATIONS HAVE TO DUKE ENERGY'S GIP?

A. Duke Energy's GIP exhibits characteristics common to such plans issued by US investor-owned utilities in recent years: (1) it was not developed according to best practices in distribution planning; (2) it recommends investment dramatically above and beyond "business as usual" investments; (3) it requests extraordinary ratemaking treatment, which would provide additional incentive to invest; and (4) it is justified by cost-benefit calculations based on irregularities and weak assumptions, as described in Witness Alvarez's testimony. I believe these characteristics render the GIP fundamentally flawed, and that the GIP would not meet North Carolina's need for low-cost, safe, reliable, and increasingly clean electricity.

The North Carolina economy and ratepayers can only bear so much rate increase. As a result, grid investments must be very carefully considered and prioritized. Failure to do so presents its own kinds of risks to the North Carolina economy. It also presents risks to the achievement of North Carolina's Clean Energy Plan,[6] as rate increases wasted on cost-ineffective investments are no longer available to fund grid capabilities offering better "bang for the buck." My testimony is intended to provide a basic technical evaluation of GIP programs and sub-components to help the Commission make informed choices regarding Duke Energy's GIP.

Q. PLEASE PROVIDE EVIDENCE TO SUPPORT YOUR ASSERTION THAT RELIABILITY OF DUKE ENERGY'S NORTH CAROLINA GRID HAS DETERIORATED SIGNIFICANTLY IN RECENT YEARS DESPITE DRAMATIC INCREASES IN GRID INVESTMENT.

A. I completed the same reliability vs. investment analyses for DEC (Figure 1) and DEP (Figure 2) that Witness Alvarez completed on a national basis, which is contained in his testimony that is being filed in this docket concurrently.[7] While growth in peak demand does justify much of DEC's and DEP's grid investment increases, DEC and DEP's respective grid investment increases exceed peak demand growth by 37% and 61%.[8] One would hope these excess investments would lead to at least some reliability improvements. Yet, as is the case nationally, DEC and DEP's performance under key indices of reliability, the

[6] Report by the North Carolina Department of Environmental Quality. October, 2019. Available here: https://files.nc.gov/ncdeq/climate-change/clean-energy-plan/NC_Clean_Energy_Plan_OCT_2019_.pdf
[7] Sources: FERC Form 1 and EIA Form 861 data, 2013 through 2018.

System Average Interruption Duration Index ("SAIDI") and System Average Interruption Frequency Index ("SAIFI"), have deteriorated significantly despite grid investment in excess of capacity needs. (Note that for SAIDI and SAIFI, lower values represent better performance.)

Figure 1: Relationship between Grid Investment and Reliability for DEC

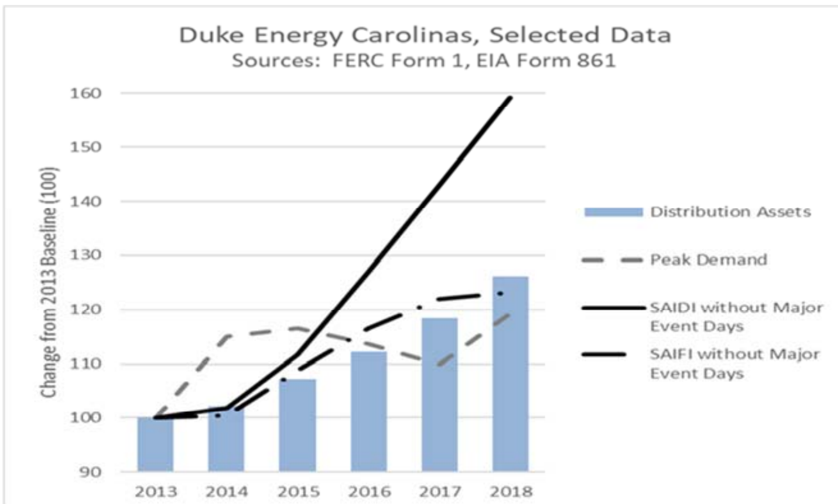
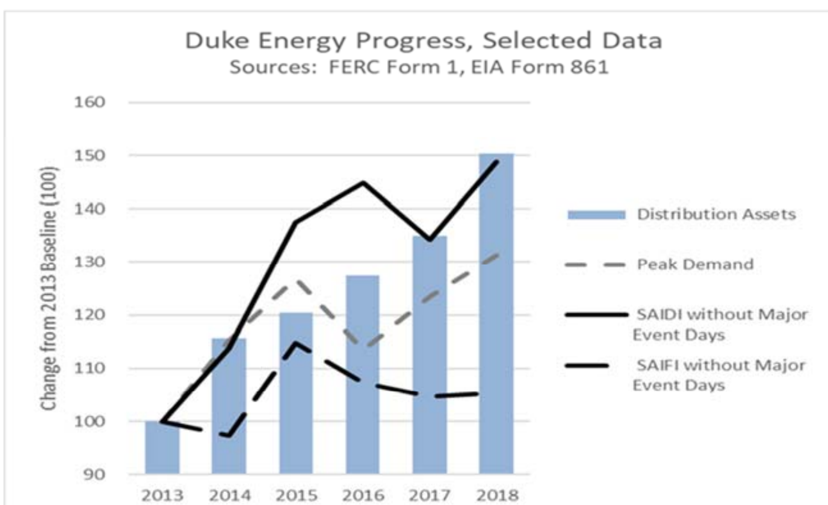


Figure 2: Relationship between Grid Investment and Reliability for DEP[9]



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[9] As referenced above, DEC and DEP are each presenting the GIP program for approval in their respective concurrent rate cases. To that end, I have included DEC *and* DEP analysis here as it supports my point that historical investments do not correlate with SAIDI and SAIFI improvements. I believe this is a key indictment of the GIP.

As shown in Figure 1, DEC's SAIDI and SAIFI performance have deteriorated almost 60% and more than 20%, respectively, since 2013 despite grid investment growth 37% greater than peak demand growth. As shown in Figure 2, DEP's SAIDI and SAIFI performance have deteriorated almost 50% and more than 5%, respectively, since 2013 despite grid investment growth 61% greater than peak demand growth.

Q. WHAT DO YOU CONCLUDE FROM THIS DATA?

A. I do not conclude from this data that investments in reliability or weather event resilience are bad ideas. Instead, I conclude from this data that the grid investments that DEC and DEP have been making in recent years do not appear to be achieving the intended results. In light of this, Duke's proposed investments in the grid to improve reliability, enhance resilience, or facilitate deployment of DERs must be very carefully considered and prioritized.

IV. GIP Programs Meriting Approval with Conditions

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. Should the Commission disagree with my primary recommendation to deny the request for approval of the GIP and institute a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process, then, in the alternative, some of the GIP programs may be approved with conditions. In this section of my testimony, I will discuss the GIP programs and sub-components that I believe, under my secondary recommendation, may merit approval with conditions. I will describe my rationale for these programs' merits, as well as conditions I believe the Commission should require in the event it approves spending for these programs and sub-components. I will conclude this section with a discussion regarding the potential value of a transparent, stakeholder-engaged distribution planning and capital budgeting process, as I believe such a process could improve the GIP even among meritorious programs. The GIP programs and sub-programs that I believe may merit approval with conditions include:

- Integrated Volt-VAR Control ("IVVC");
- Flood and Animal Mitigation portions of Transmission Hardening and Resilience;
- Long Duration Interruption/High Impact Sites;
- Enterprise Applications, ISOP software, and DER dispatch software;
- Cyber security portions of Physical and Cyber Security; and
- Power electronics for Volt-VAR Control.

Q. WHY DO YOU BELIEVE THESE GIP PROGRAMS MAY MERIT APPROVAL WITH CONDITIONS?

A. All of the GIP programs on this list satisfy one or more of the following criteria:

- They represent standard industry practice;
- They consist of software needed to optimize grid assets or operations, or to improve cyber security;
- They are likely, with conditions, to deliver benefits to ratepayers in excess of costs to ratepayers without material modifications of the program as proposed;

- They are critical to stakeholders' value that cannot be otherwise secured.

Q. WHAT CONDITIONS DO YOU RECOMMEND THE COMMISSION ATTACH TO APPROVAL OF THESE PROGRAMS?

A. The Commission should consider attaching a common set of conditions to any and every GIP program it might approve. These conditions include cost controls, operating audits, and performance measurement.

Q. PLEASE DESCRIBE THE COST CONTROL CONDITIONS.

A. As described in Witness Alvarez's testimony, there are significant differences between the program capital amounts provided in the GIP[10] and the program capital amounts provided in the benefit-cost analyses. I also note the equivocal response to a clear request during discovery about the amount of capital being requested for the GIP, to which Duke Energy responded it is only requesting, though I am paraphrasing: (1) a return on and of capital spent on GIP assets placed in service as of the closing date of this rate case; and (2) deferred accounting treatment for GIP assets placed in service between this rate case and the next rate case.[11] I find this level of ambiguity concerning, and believe the Commission should share my concern. I do not believe ratepayers will be best served if Duke Energy treats GIP capital as a pot of money it can invest as it wishes.

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[10] Oliver Direct, Exhibit 10, page 3.

[11] Duke Energy Carolinas Response to NCJC et al. Data Request No. (hereinafter, "DR") 5-4(a), NCUC Docket No. E-7, Sub 1214. attached as Stephens Exhibit 2. (References to DEC responses to data requests are to those served in NCUC Docket No. E-7, Sub 1214.)

Instead, any GIP program the Commission approves should include a clearly defined functional scope, a clearly defined geographic scope, and capital budget sufficient to secure the functionality for the defined geography. This is consistent with the accountability issue Witness Alvarez raises in his testimony, but on the cost side of the benefit-cost equation. Furthermore, I am concerned that ratepayers will bear 100% of the risk of any cost overruns or scope shortcomings. I encourage the Commission to consider cost caps for specific programs and scopes, complete with ratepayer protections (such as 50/50 cost sharing between ratepayers and shareholders for cost overruns). Finally, program cost caps should incorporate all capital for each program, including capital spent prior to the end of the test year in this rate case.

Q. PLEASE DESCRIBE THE OPERATING AUDITS.

A. This condition is closely tied to cost caps. In my experience, an investor-owned utility at risk for exceeding a cost cap with consequences will simply reduce functionality or geographic scope in order to remain under the cap/avoid the consequences. This is not the intended outcome of the cost caps condition. As a result, I also recommend operating audits, with appropriate use of random sampling, to validate the functionality and geographic scope of any and all approved GIP programs. For example, if the GIP proposes that Duke Energy will add IVVC to 1800 circuits for $200 million by 2024, an operating audit conducted in 2025 should validate that IVVC software is providing instructions to IVVC equipment installed on 1800 circuits.

Q. PLEASE DESCRIBE PERFORMANCE MEASUREMENT CONDITIONS.

A. Performance measurement should be a condition of every program for which performance is likely to be variable. Baseline performance levels should be measured before capabilities are added, and post-deployment performance should be measured on an ongoing basis. Performance measurement is critical for ensuring that ratepayer benefits are being maximized, and increased over time, but also to inform potential future expansions or curtailments of GIP programs.

In this group of meritorious programs, IVVC stands out as a program requiring performance measurement. Duke Energy should be required to report baseline and annual average voltage for every circuit with IVVC capabilities. Ameren Illinois' IVVC measurement and validation program is an excellent example of sound IVVC performance measurement.[12]

Q. BEFORE PROCEEDING, PLEASE COMMENT ON THE RESTRICTIONS THAT DUKE ENERGY IS PLACING ON DER INSTALLATIONS DUE TO VOLTAGE CONCERNS.

A. In its Method of Service Guidelines, Duke Energy describes limitations it is placing on DER locations due to operational voltage issues. The rationale for these limitations -- challenges associated with non-standard line voltage regulator ("LVR") settings – are not valid from a technical perspective. I can understand why grid operators would want to minimize the reconfiguration flexibility reductions associated with non-standard LVR settings. But new loads routinely serve to reduce reconfiguration flexibility; it is part of grid operators' job to manage around reconfiguration flexibility reductions, and they do so successfully

[12] Illinois Commerce Commission 18-0211. *Ameren Illinois Voltage Optimization Plan.* Jan 25, 2018. P. 27-30.

all the time. Regarding backfeed, it is easy to manage as long as DER relative to load is not extremely high. When DER relative to load does get high, technologies are available to manage backfeed. Nor are voltage issues generally, or the presence of IVVC capabilities specifically, a reason to restrict DER on a circuit. Capacitor banks, smart inverters, and IVVC software setting adjustments can all be employed to cope with volt-VAR issues related to DER.

To summarize, neither stakeholders nor the Commission should accept Duke Energy's limitations on DER without a technical challenge. The fact that a DER installation might make a grid operator's job more difficult is not an acceptable restriction rationale, and the software Duke Energy is installing, and which I have categorized as "merits approval with conditions" in this testimony, will help grid operators manage DER capacity growth. The unwarranted restriction of DER locations appears to me to be yet another reason to implement a transparent, stakeholder-engaged distribution planning and capital budgeting process in North Carolina.

Q. WHAT KIND OF VALUE COULD A TRANSPARENT, STAKEHOLDER-ENGAGED DISTRIBUTION PLANNING AND CAPITAL BUDGETING PROCESS DELIVER REGARDING THE MERITORIOUS PROGRAMS YOU DESCRIBE IN THIS SECTION?

A. Witness Alvarez's testimony describes a transparent, stakeholder-engaged distribution planning and capital budgeting process that warrants Commission consideration. While some will perceive such a process as an attempt to limit grid investment, I prefer to think of it as a way to optimize grid investment. For example, while I believe the GIP programs listed in this section may merit approval, I pass no judgement regarding the relative size or mix of the investments. Should the GIP devote more capital to the IVVC program and less on cybersecurity? Maybe; it depends on priorities, perceptions of threats, degree of program effectiveness, risk tolerance, and a host of other variables that exist to varying degrees within various ratepayers and stakeholders. When a utility makes these decisions for us, it can only fight stakeholders, as any decision the utility makes will put it on the wrong side of some stakeholders' interests. When a utility works with stakeholders as a trusted advisor, explaining the pros and cons of various approaches to an emerging issue or opportunity, it is able to better align goals, interests, and priorities and make the right investment choices.

V. GIP Programs Requiring Material Modifications and Conditions to Merit Approval

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will discuss the GIP programs that must be materially modified in order to merit Commission approval under my secondary recommendation, including the Self-Optimizing Grid ("SOG") and Transmission Hardening and Resilience Programs. I will recommend that the SOG budget, should the Commission approve the program, be reduced to better focus capital on high-priority circuits and sections. I will recommend that the Transmission Hardening and Resilience programs be dedicated solely to actual capacity increases designed to accommodate more DER before they can merit approval. Otherwise, I recommend the Commission reject this spending entirely. I will also identify opportunities for a transparent, stakeholder-engaged distribution planning and capital budgeting process to deliver value when considering capital outlays for these types of programs.

A. Self-Optimizing Grid

Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR DUKE ENERGY'S SOG PROGRAM?

A. The notion of "networking" circuits or substations so that a source of back-up power is available in the event the primary source fails is nothing new. Utilities, including DEC and DEP, have been sectionalizing circuits and building back-up supply lines (called tie lines) for decades. Duke Energy's SOG program simply does more of this networking, allows it to be executed remotely (without sending linemen in trucks to throw switches), and with less preparatory analysis (through software) to ensure a grid reconfiguration doesn't create more problems than it solves. However, like all investments intended to improve reliability, the law of diminishing returns applies. That is, every incremental capital dollar spent delivers less incremental reliability improvement than the capital dollar just spent. As mentioned by Witness Alvarez in his testimony, there is a balance to be struck between reliability and affordability. Taken to an extreme, our grid could be made perfectly reliable, though few would be able to afford electricity. As it relates to the SOG program, the questions are (1) to what extent/which circuits to apply it; and (2) into how many sections should each circuit be split?

Q. HOW DOES ONE DETERMINE THE NUMBER OF/SELECT CIRCUITS TO WHICH TO APPLY THE NETWORKING CONCEPT?

A. It is part art and part science, and is yet another example of why a transparent, stakeholder-engaged approach to distribution planning and capital budgeting creates value for ratepayers. All else being equal, circuits with greater numbers of ratepayers will receive greater benefits from networking than circuits with fewer numbers of ratepayers. But not all ratepayers are created equal. As the long duration interruption/high impact sites program recognizes, reliability is more critical to some facilities/districts (hospitals, airports, downtowns) than others. What I can tell you for certain is that the benefit-to-cost ratio improves as the focus of networking spending tightens. The concept is best illustrated by example. Consider six circuits, each of which has the same cost for networking, and a variety of projected benefits:

Circuit Number	Networking Cost	Projected Benefit
1	$2	$3.00
2	$2	$2.75
3	$2	$2.50
4	$2	$2.25
5	$2	$2.10
6	$2	$2.05
Totals	$12	$14.65

Assume that cost estimates are solid, but that benefit estimates are less so. As Witness Alvarez's testimony indicates, benefit estimates are generally subject to a significant number of assumptions that cannot be assured. While the networking program in the hypothetical example indicates a benefit-to-cost ratio of 1.2 to 1 ($14.65/$12), the benefit cost ratio could be improved to 1.65 to 1 ($8.25/$5) by limiting the investment to the first three circuits. Note that a benefit variance of as little as 10% makes circuits 5 and 6 cost-ineffective, and a benefit variance of as little as 15% also makes circuit 4 cost-ineffective. So, reducing the number of circuits not only improves the benefit-to-cost ratio, it reduces the risk that the treatment (in this case SOG) will cost more than the benefits delivered, particularly considering the variability surrounding benefit estimates.

Q. HOW DOES ONE DETERMINE THE NUMBER OF SEGMENTS INTO WHICH A CIRCUIT SHOULD BE DIVIDED?

A. The law of diminishing returns applies here too. Consider a circuit with 1,000 ratepayers. Splitting this circuit up into two segments will enable 500 ratepayers to receive power from a back-up source when the primary source fails, a 50% improvement. Now consider splitting this circuit into three circuits, which would enable 667 ratepayers to receive power from a back-up source when the primary source fails. While a 66% improvement is better than a 50% improvement, note that the incremental improvement of three sections over two is only 16%, while the incremental improvement of two sections over one is 50%. Each additional section – four, five, or six – will each deliver less and less incremental benefit. Such is the law of diminishing returns, and the concept is useful to consider not just within a program, but between programs, and even for an overall distribution rate base. It is yet another example of why distribution planning and capital budgets must be carefully considered and prioritized, ideally with the input of educated and informed stakeholders.

Q. HOW DO THESE OBSERVATIONS INFORM YOUR RECOMMENDATION FOR MATERIAL MODIFICATIONS TO DUKE ENERGY'S SOG PROGRAM?

A. My recommendation is that the fixed costs of the SOG proposal, including the Advanced Distribution Management System ("ADMS") and proof-of-concept ($48.9 million) be approved, while the variable portion – the extent to which SOG is deployed geographically – be cut in half (from $673.6 million to $336.8 million). While I have significant concerns about ADMS, which I will discuss, I believe this solution will increase the benefit-to-cost ratio of the SOG program, and reduce the risk that SOG capital will be applied to circuits that will not deliver benefits in excess of cost. As indicated in Witness Alvarez's testimony, the reliability of Duke Energy's benefit estimates is questionable, meaning that variability in benefit delivery is likely to be high. Stakeholder engagement could be used to establish criteria for circuit prioritization.

Another reason to cut the SOG capital budget is the high degree of variation in capital cost estimates. In discovery, Duke Energy admitted that SOG cost estimates were prepared at an AACE Class 4 level of detail.[13] Class 4 cost estimates are only accurate to within minus 30%/plus 50%, so better to approve a smaller budget until better cost estimates can be developed for specific circuits. Finally, all the conditions I described in the previous section of my testimony – cost caps, operating audits, and performance measurement – should apply to all programs, including SOG, which the Commission elects to approve (if any).

[13] DEC Response to NCJC DR 4-6, attached as Stephens Exhibit 3.

Q. WHAT ARE YOUR CONCERNS ABOUT DUKE ENERGY'S $48 MILLION ADMS PROPOSAL?

A. ADMS consists of a suite of software applications that are then combined into a single operating platform. In my experience, the value comes from the underlying software applications, including fault locating, isolation and service restoration ("FLISR") and integrated Volt-VAR control ("IVVC"). In general, with the possible exception of outage management system integration, the combination into a single operating platform, though intuitively appealing, provides little actual economic benefit. Similarly, I have seen utilities waste tens of millions of dollars pursuing grid automation – enabling software, not grid operators in control centers – to reconfigure the grid. Not only is this sort of automation extremely costly to implement, to little economic benefit, it requires an extreme, ongoing level of dedication and attention to field device software updates, GIS map system accuracy, accurate location and device setting monitoring, communications network attention, and logical equipment identification. If the logical specifications do not precisely match physical specifications, for every device, 100% of the time, automation efforts will fail.[14] When O&M budgets are stretched, or under the pressure of a service restoration effort, humans take shortcuts. Full grid automation, where some see ADMS heading, thus requires a level of management and employee attention that may be unattainable, and involves a great deal of risk. Due to the underlying suite of software applications, I hesitate to recommend the Commission reject ADMS. But, due to the

[14] Many of these concerns are described in a US Department of Energy whitepaper dedicated to the subject. US Department of Energy. *Voices of Experience: Insights into Advanced Distribution Management Systems*. Whitepaper. February, 2015.

challenges and overreaches I describe, I absolutely recommend the Commission apply cost cap and operating audit conditions to any self-optimizing grid and ADMS capital spending the Commission might approve.

B. Transmission Hardening and Resilience (Excluding Flood and Animal Mitigation)

Q. WHAT MATERIAL MODIFICATIONS DO YOU RECOMMEND FOR DUKE ENERGY'S TRANSMISSION HARDENING AND RESILIENCE PROGRAM?

A. While my suggested modifications to the self-optimizing grid program amounted to a relatively simple reduction in scope, my suggested modifications to the transmission hardening and resilience program amount to a complete redesign of the program and a repurposing of the $120 million transmission hardening and resilience budget (excluding substation flood and animal mitigation components, which I included in the "merit approval" category).

Q. WHY DO YOU RECOMMEND THE TRANSMISSION HARDENING AND RESILIENCE BUDGET BE COMPLETELY REPURPOSED?

A. Duke Energy describes its transmission hardening and resilience program as a way to improve reliability, projecting that ratepayers will receive $2 billion in economic benefits. However, given the extremely low historical failure rates of the transmission equipment DEP proposes to replace, including static lines and support structures, there is no way the replacements proposed can possibly avoid the number of failures required to produce the economic benefits projected.[15] In my experience, low transmission failure rates are common, as transmission

[15] Witness Alvarez provides these historical failure rates in his testimony.

designers recognize the larger number of ratepayers impacted by failures on such systems, and overbuild accordingly. But my concerns regarding benefit projects are trumped by an even bigger concern: the transmission hardening and resilience program proposed will not increase the capacity of the system to accommodate greater DER capacity by a single watt.

Q. ARE YOU SURE? DUKE ENERGY'S GIP STATES ITS TRANSMISSION AND RESILIENCE PROGRAM "BEGINS TO PAVE THE WAY FOR MORE DER INTERCONNECTIONS."

A. As part of the transmission hardening and resilience program, DEP is only replacing some support structures (poles) and static lines. These activities will not increase DER capacity. Nor, as described above and by Witness Alvarez, will these activities deliver the reliability benefits Duke Energy projects. My recommendation is to repurpose the entire $120 million Duke Energy proposes to invest in its transmission hardening and resilience program specifically to increase the system's DER capacity. Stakeholder engagement would be valuable in allocating this capital in ways that maximize the amount of new DER capacity accommodated for the least cost. The deficiencies in Duke Energy's transmission hardening and resilience proposal illustrate the potential value of a transparent, stakeholder-engaged distribution planning and capital budgeting process.

VI. GIP Programs That Should Be Rejected Due to Lack of Cost Effectiveness/Compliance with Standard Industry Practice

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will discuss GIP programs that should be rejected in any scenario. None of these programs are standard industry practice as they are generally recognized as not cost-effective. They include:

- Targeted Undergrounding ($114.5 million);
- Distribution Transformer Retrofits ($118.0 million);
- Transformer Bank Replacements ($116.4 million);
- Oil-Filled Breaker Replacements ($200.3 million); and
- Substation Physical Security ($110.7 million).

A. Targeting Undergrounding

Q. WHY DO YOU BELIEVE TARGETED UNDERGROUNDING MERITS REJECTION?

A. Undergrounding of overhead lines is not a standard industry practice for many reasons. Undergrounding may be intuitively appealing, but it is not the panacea that utilities would like stakeholders to believe. While undergrounding reduces the risk of service interruptions due to vegetation contact and weather, it increases the risk of service interruptions due to flooding and digging. While undergrounding reduces the hassle associated with repairing lines in residential ratepayers' backyards, the time to locate and repair underground faults generally takes longer than the time to locate and repair faults on overhead lines. While aesthetically appealing in principle, in practice almost 100% of utility poles will remain in place, supporting telephone, Internet, and cable television service lines. While undergrounding may eliminate a small portion of Duke Energy's tree trimming costs, some other service provider will still need to clear vegetation, that means ratepayers will still pay; underground cable is also more costly than overhead conductor, and must be replaced more frequently. A Lawrence Berkeley National Laboratory review of undergrounding programs also noted an increase in utility employee safety risks associated with undergrounding.[16]

Furthermore, undergrounding is extremely costly and not cost-effective, and it is not simply my experience that tells me so. The Lawrence Berkeley National Lab undergrounding study indicates that the benefit-to-cost ratio of undergrounding is 0.3 to 1.0 (that is, costs exceed benefits by a factor of more than three).[17] For these reasons, the Virginia State Corporation Commission ("SCC") rejected undergrounding programs proposed by Dominion multiple times. Duke Energy's program proposes to underground the lines serving just 22,477 ratepayers[18] at a cost of $169.3 million,[19] or at least $7,500 per ratepayer undergrounded. To justify the program, Duke Energy claims that undergrounding will reduce the momentary outages to commercial and industrial ("C&I") ratepayers upstream of the residential areas. In fact, Duke Energy attributes of 90% of the benefits it projects from targeted undergrounding to this single value proposition.

Q. DO YOU BELIEVE THAT JUSTIFYING THE INSTALLATION OF TARGETED UNDERGROUNDING BASED ON THE EFFECT OF UPSTREAM MOMENTARY OUTAGES IS INAPPROPRIATE?

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[16] Larsen P. A Method to Estimate the Costs and Benefits of Undergrounding Electricity Transmission and Distribution Lines. Lawrence Berkeley National Laboratory. October 2016. Page 7.

[17] Ibid, parts of the document not paginated, see PDF file page 42.

[18] Oliver Direct, Ex. 7 workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx", tab "Area Data – Condensed", line "Total Ratepayers Affected".

[19] Ibid, tab "All Years Tab Summary", cell D21.

A. As indicated in Mr. Alvarez's testimony, the cost per momentary outage to various rate class ratepayers is exaggerated. In addition, I would like to point out a few factors that contribute to Duke Energy's exaggeration of the amount of upstream momentaries caused by backlot line overhead lines.

First, Duke Energy admitted in discovery that not all outages result in an upstream momentary event.[20] The purpose of coordinating the operation of fuses with upstream devices is often intended to eliminate an upstream operation. That is to say, that the upstream relay is set such that the downstream fuse will clear or blow, for faults of sufficient magnitude, resulting in no upstream momentary outage.

Second, the reason for most momentary outages is that the utility has installed a "Fast" or "Fuse Saving" relay setting on the upstream device, which is designed to open the upstream device and allow a fault to clear. This opening operation is the momentary outage. These upstream device settings are typically set for one fast trip before moving to the slower trips which would cause a downstream device such as a fuse to clear. The point is, a simple adjustment to upstream device trip settings can eliminate C&I momentaries caused by downstream events.

Third, Duke Energy's reliability improvement estimates assume 2.7 momentaries for every sustained outage. I believe this estimate is too high. As indicated above, relays are typically set for one fast trip, not multiple fast trips,

[20] DEC Response to NCSEA DR 3-32, attached as Stephens Exhibit 4.

which would result in one momentary upstream outage before the fuse clears, not 2.7. The fuse again would be coordinated with the relay setting following the "Fast" trip setting such that the fuse would clear prior to the upstream device opening again after the fast trip opening. This would result in one momentary for upstream ratepayers. The only reasonable course of action is to evaluate the upstream momentaries on a circuit-by-circuit basis.

Fourth, Duke Energy admitted in discovery that eliminating the "Fast" Trip on the upstream device would eliminate most of the momentaries experienced by the upstream C&I ratepayers.[21] Duke Energy did point out that this would result in increased downstream outages and trips to the field; however, the value Duke Energy placed on upstream C&I ratepayer momentaries greatly outweighs the value of downstream outages. If this is the case, then the best course of action would be to eliminate the "Fast" trip setting on upstream devices rather than spend $114.5 million undergrounding downstream segments in just 55 neighborhoods. I note that estimated economic benefits for many GIP programs consist largely or mainly of a reduction in upstream momentaries for C&I ratepayers. The preceding comments apply to all of these programs.

Finally, I must comment on the extremely high costs of undergrounding. While Duke Energy estimates the cost at $850,000 per undergrounded mile, I note that the proposed undergrounding program incorporates "looping" of underground

[21] DEC Response to NCJC DR 5-33, attached as Stephens Exhibit 5.

cables -- burying twice as much cable as would otherwise be required[22] – to further enhance reliability and flexibility. The cost of undergrounding therefore amounts to $1.7 million per mile of overhead conductor undergrounded, or 4.5 times the cost of replacing overhead conductor with new,[23] even if it were warranted. While this finding does not change the miles or budgets of the proposed targeted undergrounding program, I feel it is important for the Commission to understand just how expensive this program is. Given the small incremental improvement in reliability, the negative benefit-to-cost ratio found in research, and the low-cost alternatives available to improve reliability I describe above, the Commission must strongly consider better ways to spend the capital for which customers will be asked to pay. Like all other GIP programs, a transparent, stakeholder-engaged review of undergrounding benefits, costs, and options would likely result in a different decision regarding the practice than Duke Energy proposes.

B. Distribution Transformer Retrofits

Q. WHY DO YOU BELIEVE THE DISTRIBUTION TRANSFORMER RETROFIT PROGRAM MERITS REJECTION?

A. The distribution transformer retrofit program that Duke Energy is proposing is not standard practice, and is not likely cost-effective. Duke Energy operates 784,000 distribution transformers in North Carolina; in an average year slightly fewer than

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[22] Duke Energy Progress Response to NCJC Data Request 6-4, Docket No. E-2, Sub 1219, attached as Stephens Exhibit 6.

[23] Oliver Direct, Ex. 7 workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx", tab "Lookups", line 23 "Cost/Mile to Replace Backlot Conductor" ($375,000) divided into $1.7 million.

6,000 of them, or less than 1%, will fail.[24] As with targeted undergrounding, the value proposition proffered by Duke consists almost entirely of protecting C&I ratepayers from downstream service outages; 93% of the benefits Duke Energy projects stem from this claim.[25] Duke indicates that the transformers and secondary systems that are planned for retrofit are operating safely.[26] Additionally, Duke could provide no indication of outages or outage complaints associated with these transformers on secondary lines[27]

Duke indicated that many of the transformers that are involved in the retrofit project are Completely Self Protected ("CSP") transformers.[28] These transformers have internal fuses that protect the transformer from internal faults. Thus, even though the distribution transformer retrofit project is intended to protect the transformer and the secondary line, the program is duplicative for the transformer portion of the value proposition.

In discovery, Duke Energy indicated the trip setting on the transformer retrofit devices would be set such that the retrofitted distribution transformer would trip before any upstream devices could trip.[29] This is counterproductive. The reason for enabling a fast trip setting on upstream devices is to allow a fault to clear before the downstream device (in this case the retrofitted distribution

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[24] Oliver Direct, Ex. 7 workbook "HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx", tab "Selection Metric – Tx Retrofit NC", cell C31 plus cell C34 (incidents) divided by cell 65 (total transformer count).
[25] Ibid. Tab "NPV-Tx Retrofit NC".
[26] DEC Response to NCJC DR 8-34, attached as Stephens Exhibit 7.
[27] *Id*.
[28] DEC Response to NCJC DR 8-34. DEC could not provide an exact count; however, most of the distribution transformers installed by utilities in the last 40 years have been of the CSP type.
[29] DEC Response to NCJC DR 5-40, attached as Stephens Exhibit 8.

transformer) clears or opens. The transformer retrofit program would install a device downstream that clears or opens before the upstream fast trip device can prevent it from operating. This is clearly counterproductive and a waste.

C. Transformer Bank Replacement

Q. EXPLAIN WHY THE TRANSFORMER BANK REPLACEMENT PROGRAM SHOULD BE REJECTED.

A. Substation transformers are typically situated in groups of three, constituting a transformer bank. Unlike distribution transformers, substation transformers (also known as transmission transformers) typically serve one or two thousand ratepayers each. However, as transformer oil can be tested, and used to predict transformer failure, there is no reason whatsoever to replace transformers in the absence of test results. As a result, substation transformer oil testing and failure prediction is a standard industry practice; prospective substation transformer replacement in the absence of test results is not.

Witness Alvarez provides historical substation transformer failure rates in his testimony; they are extremely low, as I would expect. The large benefits Duke Energy projects from avoiding future transformer failures through prospective replacement do not square at all with historically low transformer failure rates. Prospective substation transformer replacement, and particularly the proactive replacement of entire transformer banks, in the absence of test results, should be rejected.

D. Oil-Filled Breaker Replacement

Q. EXPLAIN WHY THE OIL-FILLED BREAKER REPLACEMENT PROGRAM SHOULD BE REJECTED.

A. Circuit breakers, like transformers, can be tested. It is standard industry practice to test circuit breakers at regular intervals, and to track the number of operations (trips) for each breaker. When a circuit breaker fails a test, or reaches its rated number of operations, it is standard industry practice to replace it. Replacing circuit breakers in the absence of test failure or operating counts is not standard practice.

Again, there is a reason prospective circuit breaker replacement is not standard industry practice. Witness Alvarez provides historical circuit breaker failure rates in his testimony; as with transformer failures, the failure rate has been extremely low. The large benefits Duke Energy projects from avoiding future circuit breaker failures through prospective replacement do not reconcile with historically low transformer failure rates.

Q. BUT DUKE ENERGY DESCRIBES BENEFITS OTHER THAN RELIABILITY IMPROVEMENTS FROM CIRCUIT BREAKER REPLACEMENT, DOES IT NOT?

A. Yes. Duke Energy claims that the new circuit breakers will have remote monitoring and control capabilities that the oil circuit breakers do not have. While this may be true, I note that retrofit kits are available to provide these same capabilities for oil circuit breakers at the fraction of the cost of a new circuit breaker. Duke Energy also claims that about one-third of the economic benefits of the circuit breaker replacement program stem from the avoidance of replacement in the future. I do not see this as a "benefit" at all. When a circuit breaker needs to be replaced, it should be replaced. Replacing a circuit breaker before it becomes necessary to do so does not avoid any costs at all; rather, it advances the cost, requiring ratepayers to pay today for something they could have been spared until some future test failure. I note Duke Energy applies this nonsensical benefit to other programs too, including targeted undergrounding and transformer bank replacement. Witness Alvarez quantifies this in his testimony regarding overstated benefits.

E. Substation Physical Security

Q. EXPLAIN WHY THE PHYSICAL SUBSTATION SECURITY PROGRAM SHOULD BE REJECTED.

A. As with the other programs that merit rejection, there is no standard industry practice or security standard associated with the physical substation security upgrades Duke Energy is proposing. The physical substation security program includes the installation of high-security fencing, gates, cameras, and lighting at a cost of $4.2 million per substation. This amount includes $800,000 per substation just for a prefabricated building to house physical security equipment.[30] At a proposed budget of $110 million, this program will upgrade the physical security of just 27 substations. Although that will leave Duke Energy with 2,088 (99%) of its substations with standard fencing, I am pleased to report that Duke Energy has never recorded a single incident of unauthorized substation intrusion.[31] There must be more valuable ways for Duke Energy to deploy capital, and this proposed

[30] DEC Response to NCJC DR 2-4, attached as Stephens Exhibit 9.
[31] DEC Response to NCSEA DR 2-19 (b), attached as Stephens Exhibit 10.

program illustrates another potential opportunity for a transparent, stakeholder-engaged distribution planning and capital budgeting process to create value for ratepayers.

VII. GIP Programs That Should Be Rejected Pending Further Evaluation

Q. PLEASE PROVIDE A PREVIEW OF THIS SECTION OF YOUR TESTIMONY.

A. In this section of my testimony, I will describe GIP programs that should be rejected pending further evaluation, because critical evaluations are missing that will require extensive effort beyond the scope of this proceeding. I will also identify opportunities for a transparent, stakeholder-engaged distribution planning and capital budgeting process to deliver value when considering these types of programs. Programs that should be rejected pending further evaluation include:

- Enterprise Communications Mission Critical Voice, Data ($52.5, $107.1 million);
- Distribution Automation ($194.3 million); and
- Transmission System Intelligence ($86.4 million).

A. Mission Critical Voice and Data Network Programs

Q. WHAT CRITICAL EVALUATIONS ARE MISSING FROM DUKE ENERGY'S PROPOSED VOICE AND DATA NETWORK DEVELOPMENT PROGRAMS?

A. Witness Alvarez describes the evaluations missing from these proposed programs, so I will not repeat those here. While neither Witness Alvarez nor I are communications experts, I appreciate his concern that Duke Energy completed no technical or economic make vs. buy evaluation of alternatives to Duke Energy's $160 million proposal to build proprietary voice and data communication networks.[32] In this Internet of Things age, when public wireless carriers are introducing high data transfer rates, dedicated bandwidth, and ever-improving cybersecurity capabilities, it seems more than appropriate to me that an in-depth evaluation of Duke Energy's claimed voice and data requirements, along with potential options to satisfy them, be conducted. Stakeholders may need to enlist expert services to properly participate in such an effort, but that seems preferable to "waving through" a $160 million investment that has not been thoroughly evaluated. Due to the lack of technical or economic make vs. buy analyses, I agree with Witness Alvarez that this GIP program be rejected pending a more thorough evaluation.

B. Distribution Automation and Transmission System Intelligence Programs

Q. WHAT CRITICAL EVALUATIONS ARE MISSING FROM THE DISTRIBUTION AUTOMATION AND TRANSMISSION SYSTEM INTELLIGENCE PROGRAMS?

A. Duke Energy provides no benefit-cost analyses for these programs, claiming they are "modernization" programs. I do not understand why categorizing them as modernization programs excuses Duke Energy from the obligation to conduct benefit-cost analyses. Indeed, in GIP descriptions of these programs, improvements in reliability and resilience are featured. For all other GIP

[32] NCUC Docket # E-7 Sub 1214. DEC Responses to NCSEA DR 2-52(d) and 2-53(e).

programs in which improved reliability and resilience are claimed, benefit-cost analyses were developed; why not for these two programs?

I agree that benefits can be difficult to quantify for some programs, and that some programs merit approval without a benefit-cost analysis, or with a negative benefit-cost analysis. Indeed, I categorized several GIP programs as "merit approval with conditions" despite the lack of a benefit-cost analysis. However, it seems to me that anticipated reliability and/or resilience benefits should be quantified for any program that is promoted as beneficial to these outcomes. Failure to quantify the benefits of programs that offer quantifiable benefits represents a lack of accountability for benefit delivery. I therefore recommend the Commission reject these programs until Duke Energy completes benefit-cost analyses for them.

VIII. Summary and Recommendations

Q. PLEASE SUMMARIZE YOUR TESTIMONY AND RECOMMENDATIONS.

A. I began my testimony with context, describing how utilities have conducted distribution planning to incorporate new technologies and technical challenges for over a century. I then discussed how investor-owned utilities are changing their approach from distribution planning to a focus on maximizing capital investment. I presented historical evidence indicating that the reliability of Duke Energy's grid in North Carolina has deteriorated significantly in recent years despite dramatic increases in grid investment, confirming locally the phenomenon Witness Alvarez describes nationally: grid reliability does not necessarily improve with grid investment.

My testimony then continued with critical evaluations of the individual programs or sub-components that make up Duke Energy's GIP. My testimony placed Duke Energy's GIP programs and sub-components into one of five categories: (1) Those that merit approval with conditions; (2) Those that only merit approval with material modifications and conditions; (3) Those that do not merit approval due to lack of cost-effectiveness/compliance with standard industry practices; (4) Those that merit rejection pending further evaluation; and (5) Those being considered in other dockets. I justify categorization through testimony which evaluates the relative merits of each GIP program and sub-component relative to costs, or identifies missing information prohibiting such evaluation. My testimony also describes the general conditions I recommend the Commission establish for any GIP program it approves, and modifications specific to the self-optimizing grid and transmission hardening & resilience programs. My testimony concludes with recommendations for the Commission's consideration, including both primary and secondary (program-specific) recommendations.

My primary recommendation, consistent with Witness Alvarez's recommendation, is for the Commission to reject Duke Energy's GIP. Instead, I recommend the Commission establish a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting process. Witness Alvarez's testimony provides additional descriptions and justifications for such a process. In the event the Commission rejects my primary recommendation, I recommend the Commission follow my program-specific guidance as secondary recommendations. I also describe conditions I recommend the Commission establish for any GIP programs approved, including (1) performance measurement; (2) cost caps and associated operating audits; and (3) rejection of cost recovery for assets placed into service in the test year that are not standard industry practice/not cost effective. I also recommended the Commission reject deferral accounting because I believe the practice encourages investment in sub-optimal grid programs. My testimony describes why many GIP programs are sub-optimal.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE

I certify that the parties of record on the service list have been served with the Direct Testimony of Dennis Stephens on Behalf of the North Carolina Justice Center, North Carolina Housing Coalition, Natural Resources Defense Council, and Southern Alliance for Clean Energy either by electronic mail or by deposit in the U.S. Mail, postage prepaid.

This the 13th day of April, 2020.

s/ Gudrun Thompson

Gudrun Thompson

Curriculum Vitae – Dennis Stephens EE

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Profile

Mr. Stephens has over 35 years' experience in electric and gas distribution grid planning, design, operations management, and asset management, and the innovative use of technology to assist with these functions. He spent his entire career at Xcel Energy and its subsidiary Public Service Company of Colorado, a distribution utility serving 1.5 million electric customers and 1.4 million gas customers. After a series of electrical and gas engineering and management roles of increasing responsibility, Mr. Stephens retired as the Director of Innovation and Smart Grid Investments for all of Xcel Energy's electric and gas distribution businesses in 2011. He now works for the Wired Group and its clients on a part-time basis.

Career History (all positions with Public Service Company of Colorado or its parent, Xcel Energy)

1976 -- Planning Engineer. Performed electric distribution system planning for Southeast Denver, Boulder, Front Range and Cheyenne divisions, including system protection, voltage support and distribution system design.

1983 – Senior Engineer, Electric Distribution Planning. Provided direction and guidance for junior engineers. Led special projects relating to electric distribution system reliability and design. Promoted to Supervisor of Electric Distribution Planning with a staff of 12 electrical engineers with responsibility for capacity and reliability planning.

1988 -- Manager of Operations, Colorado Front Range Division. Responsible for all electric and gas distribution operations, including a high-pressure gas system (engineering, operations, and construction).

1994 -- Manager of Operations & Maintenance Engineering, Southeast Denver. Managed the design of gas and electric distribution system replacements.

1997 -- Manager, Distribution Reliability Assessment, Xcel Energy South (CO, WY, TX, OK). Led an engineering team focused on electric distribution grid reliability and capacity.

1998 -- Director of Electric and Gas Operations, Southwest Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction in the Southwest Denver Division.

1999 -- Director of Operations, City and County of Denver Division. Responsible for all aspects of electric and gas engineering, operations, and construction for Division, including downtown Denver. Promoted to Director, New Construction of electric and gas systems for the entire metro area.

2001 -- Director Electric Distribution Asset Strategy, Xcel Energy. Developed and implemented asset management strategies for all electric distribution assets in Xcel Energy's 8-state service area.

2005 -- Director of Utility Innovations and Smart Grid Investments. Led Xcel Energy's Utility Innovations department, developing and implementing new technologies and business processes in multiple electric and gas distribution functional areas. Advanced the concept of an Intelligent Network at Xcel Energy, and led several aspects of the SmartGridCity® demonstration project in Boulder, Colorado. Department secured a national Edison Award for Innovation in 2006. Retired in 2011.

2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

Smart Grid Solutions Development, 2010. Worked with several large solution providers to develop and implement technical distribution grid solutions and innovations, including IBM, ABB, and Siemens.

DER Integration Strategy and Roadmap Development, 2009. Established DER integration strategy and road-maps for Xcel Energy, including technology and capability roadmap for high DER penetration geographies in Boulder, Colorado.

SmartGridCity™ Project Development, 2008. Developed the technical foundations for the SmartGridCity project in Boulder, Colorado (46,000 customers).

Distribution Automation Design, 2007. Worked with ABB Corporation to design software to identify and locate failures in underground cable. The ABB Smart Analyzer™ was programmed with three traps to capture detailed information using Oscillography/Digital Fault Records (O/DFR).

Utility Innovations Program Development, 2006. Led the development of Xcel Energy's Utility Innovations program, for which Mr. Stephens' team receive a national Edison Award.

Distribution Asset Optimization Process, 2005. Taking advantage of SPL's Centricity Outage Management Program and Itron's Real Time Performance Management system (RTPM), developed a Distribution Asset Optimization process by mining AMI meter data and asset utilization information in the development of an enhanced asset loading forecasting process. The process took advantage of the systems' abilities to forecast sudden changes in usage patterns to take proactive mediation of equipment overloading.

Distribution Asset Optimization Software Development, 2004. Worked with Itron on the development of a Distribution Asset Optimization software program.

Fixed AMI Communications Network Development, 2003. Worked with Itron to pilot one of the first applications of a fixed wireless radio network to collect data from customer meters.

Electric Asset Management Strategy Development, 2002. Developed Xcel Energy's Electric Distribution Asset Management Strategy

Automated Switching System Deployment, 2001. Worked with S&C Electric Corporation to deploy its Intelliteam™ devices on Xcel Energy's distribution grid to reduce the number of customers impacted by an outage by isolate faults through automated switching routines.

High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included community engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Testimony before the Indiana Utility Regulatory Commission on behalf of the City of Indianapolis critiquing Indianapolis Power and Light's proposed $1.2 billion Grid Improvement Plan. Cause 45264. October 7, 2019. The proceeding is still underway.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019. The investigational proceeding is still underway.

New Hampshire Public Utilities Commission Distribution Planning/Grid Modernization Proceeding. Comments in IR 15-296 describing a transparent, stakeholder-engaged distribution planning process. The investigational proceeding is still underway.

Pacific Gas and Electric 2019 General Rate Case. Testimony in A.18-12-009 related to $270 million in proposed "Integrated Grid Platform" investments, part of a long-term plan featuring an Advanced Distribution Management System (ADMS) implementation likely to cost as much as $644 million. As an "integration" software package of little benefit, Mr. Stephens' testimony rejected PG&E's proposal in favor of several individual ADMS components of greater value PG&E failed to propose, such as a Distributed Energy Resource Management System (DERMS) and an automated volt-VAr control system for conservation voltage reduction. A Settlement Agreement has been filed.

Southern California Edison 2017 General Rate Case. Testimony in A.16-09-001 related to $2.3 billion in proposed grid modernization investments. Though portrayed by the Company as "required" to accommodate higher levels of distributed energy resources like photovoltaic solar panels, Mr. Stephens' testimony identified appropriate investment proposals (related to grid state monitoring, modeling, and frequent grid reconfiguration) while rejecting proposals which did not return benefits in excess of costs for customers (4kV circuit elimination and centralized, automated grid reconfiguration. as well as the systems and communications associated with centralized, automated grid reconfigurations). As a result of Mr. Stephens's testimony, the California PUC rejected $462 million in unnecessary grid investments requested by SCE.

Pacific Gas and Electric 2016 General Rate Case. Testimony in A.15-09-001 related to $100 million in proposed grid modernization investments. Though portrayed by the Company as "required" to accommodate higher levels of distributed energy resources like photovoltaic solar panels, Mr. Stephens' testimony rejected many proposed grid upgrades as either premature (due to insufficient DER on any one circuit or location) or unnecessary (due to safeguards in standard photovoltaic grid interconnection equipment). The California PUC rejected $60 million in unnecessary grid investments requested by PG&E as a result of Mr. Stephens's testimony.

Notable Publications and Presentations

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Paul Alvarez & Sean Ericson. Accepted for publication by Public Utilities Fortnightly. Anticipated publication June, 2019.

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Paul Alvarez for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Paul Alvarez for GridLab. October 5, 2018.

DistribuTECH 2010, Tampa, Florida. "Realizing the Benefits of DER, DG and DR in the Context of Smart Grid"

OSI 2008 User's Conference, Denver, Colorado; DistribuTECH 2007, San Diego, California. "Smart Grid City: A blueprint for a connected, intelligent grid community"

ABB 2007 World Conference, Jacksonville, Florida. "Use of Distribution Automation Systems to identify Underground Cable Failure"

North American T&D Conference 2005, Toronto, Canada; Itron 2005 User Conference, Boca Raton, Florida. "Xcel Energy Utility Innovations and Distribution Asset Optimization"

DistribuTECH 2005, San Diego, California. "How Advanced Metering Technology is Driving Innovation at Xcel Energy"

Education

Bachelor of Science Degree in Electrical Engineering, 1975, University of Missouri at Rolla.

Awards

National Edison Award for Utility Innovations, 2006.

Stephens Exhibit -2

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 5

Docket No. E-7, Sub 1214

Date of Request: January 16, 2020
Date of Response: January 27, 2020

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The attached response to NCJC Data Request No. 5-4, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

5-4. Refer to the Oliver testimony regarding the Grid Improvement Plan generally.
a. For what Grid Improvement Plan capital amount, over what years, is Duke requesting approval from the North Carolina Utilities Commission?
b. Is Duke requesting approval from the NCUC for 2019 Grid Improvement Plan capital spending in this rate case? If so, please provide amounts and detail by program, as well as where the total can be found in test year adjustments or other rate case detail.
c. Is Duke requesting approval from the NCUC for Grid Improvement Plan capital spending beyond 2022?
d. Explain how Duke intends to secure approval to recover a return of and on Grid Improvement Plan capital spending beyond 2022.
e. If Duke is not requesting approval for spending beyond 2022, explain why several benefit-cost analyses include benefits for capital spending beyond 2022.

Response:

a. Refer to attachment PS DR 36-3 for the GIP capital investments included in the current rate request. The amount is subject to update through January 31, the capital cut-off date for this case. Additionally, Duke is requesting deferral accounting for 2020 -2022 GIP capital assets placed in service until they can be requested for recovery in the next rate case.
b. See a. above.
c. No
d. This has not been determined.
e. The GIP CBA's used a 30-year evaluation period for the 3-year capital investment. The exception being DEC IVVC as it has an estimated deployment timeframe of 4 years.

Stephens Exhibit -3

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 4

Docket No. E-7, Sub 1214

Date of Request: January 10, 2020
Date of Response: January 21, 2020

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The attached response to NCJC Data Request No. 4-6, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

4-6. Refer to the Oliver testimony, workbook SOG-DEC_NC_19-22_vF_rev8 9-2-19.xlsx, tab “Partial-SOG Calcs”.
a. Provide the AACE class code for each of the cost estimates in this spreadsheet.
b. Provide all data sources, worksheets and calculations used to develop the “Switch Automation and Circuit Segmentation Allocation” of “78%” and the “Modular Dist. Control Device POC & Advanced DMS Allocation” of “22%”

Response:

a. The collective SOG estimate represents a Class 4 level estimate

b.. The allocation factors for the $126M Additional Investment assigned to Partial SOG utilizes the Full SOG ratio of the NPV capital cost total for each of the two individual components, Switch Automation and Modular Distribution Control, to the summary total of those two line items. However, upon further consideration subsequent to the final CBA filed, 100% of the $126M in Additional Investment should be related to the Switch Automation cost line item. This is an information only revision; there is no impact to the CBA results as filed.

Duke Energy Carolinas
Response to
North Carolina Sustainable Energy Association Data Request
Data Request No. NCSEA 3

Docket No. E-7, Sub 1214

Date of Request:	**December 20, 2019**
Date of Response:	**January 2, 2020**

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The attached response to NCSEA Data Request No. 3-32, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analyst, Distribution Finance – Carolinas, and was provided to NCSEA under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

Refer to the Targeted Undergrounding program generally.
a. Confirm that not all faults resulting in an outage, that occur on the load side of fuses, will result in an operation of an upstream protective device such as a Station Breaker or Recloser. If this cannot be confirmed, please explain.
b. Confirm that In determining the number of momentaries that affect upstream customers, Duke assumed that all outages in which a downstream fuse cleared the outage, resulted in one or more operations of an upstream device, such as a station breaker or a recloser, and thus resulted in one or more momentary outage for all upstream customers. If this cannot be confirmed, please explain.
c. Confirm that, on circuits for which undergrounding is planned, that Duke assumed that all upstream momentary outages result from an outage where a fuse has cleared the outage downstream. If that cannot be confirmed, i.) explain the other scenarios causing momentaries; and ii.) provide the percentage of times that the other scenarios occur.
d. Confirm that faults which do not result in an upstream operation of protective devices such as station breakers or recloser, do not result in a momentary outage for upstream customers. If this cannot be confirmed, please explain.
e. For faults on the load side of primary fuses, on the circuits for which undergrounding is planned, provide the percent of these faults which resulted in the operation of the station breaker.
f. For faults on the load side of primary fuses, on the circuits for which undergrounding is planned and for which at least one recloser exists, provide the percent of these faults which resulted in the operation of an upstream recloser.

Response:

a. DEC's overhead system is designed such that a fault beyond a first stage fuse should allow an upstream reclosing device (i.e. recloser or circuit exit breaker) to operate 1 or more times to try and let the fault clear itself before the fuse blows. We cannot confirm that all faults on the load side of a fuse will result in an operation of an upstream protective device.
b. Confirmed.
c. Not confirmed.
i. Momentaries will occur where the fault is downstream from a recloser/circuit exit breaker but upstream from a fuse or other protective device.
ii. Momentaries will not occur where the fault is on underground downstream from a fuse as our system is designed to not reclose on underground faults.
d. Confirmed.
e. Data not available. See response to 3-26(b)
f. Data not available. See response to 3-26(b)

Stephens Exhibit -5

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 5

Docket No. E-7, Sub 1214

Date of Request: January 16, 2020
Date of Response: January 27, 2020

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The attached response to NCJC Data Request No. 5-33, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analyst, Distribution Finance – Carolinas, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

5-33. Refer to DEC's response to NCSEA DR 3-32, and to the Targeted Undergrounding program generally. DEC's response to NCSEA DR 3-32 states: "DEC's overhead system is designed such that a fault beyond a first stage fuse should allow an upstream reclosing device (i.e. recloser or circuit exit breaker) to operate 1 or more times to try and let the fault clear itself before the fuse blows. We cannot confirm that all faults on the load side of a fuse will result in an operation of an upstream protective device."
a. Confirm that if the Fast Trip or Fuse Saving design feature referred to above were removed from the system, then all of the upstream momentaries projected in the TUG analysis would be eliminated. If this cannot be confirmed, please explain.
b. Confirm that fault current levels on the load side of a fuse may be such that the upstream device will bypass the fuse saving trip setting and not result in a momentary operation of an upstream protective device. If this cannot be confirmed, please explain.
c. Refer to the statement "We cannot confirm that all faults on the load side of a fuse will result in an operation of an upstream protective device". Confirm that Duke does not know how many of the sustained outages actually result in an upstream momentary under the current design.

Response:

a. If the Company removed the Fast Trip feature from upstream reclosing devices it would degrade the service to all the customers on the circuit as it would increase the number of sustained outages due to temporary faults that would have normally cleared because of the Fast Trip. The removal of the Fast Trip from upstream reclosing devices would also lead to more equipment damage as it would cause the fault current to remain on the system for longer times before being cleared.
b. It is possible that fault current levels on the load side of a fuse may be such that the upstream device will not operate on a fast trip.
c. While the Company cannot capture all upstream momentary operations associated with downstream faults, the reclosing devices are designed to fast trip for faults downstream to prevent a sustained outage due to a temporary fault, and we know from years of experience that this is the case.

Duke Energy Progress
Response to
NCJC Data Request
Data Request No. 6

Docket No. E-2, Sub 1219

Date of Request: February 25, 2020
Date of Response: March 3, 2020

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The attached response to NCJC Data Request No. 6-4, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

NCJC
Data Request No. 6
DEP Docket No. E-2, Sub 1219
Item No. 6-4
Page 1 of 1

Request:

6-4. Refer to DEP's response to NCSEA DR 3-5, attachment "NCSEA DR 3-5 TUG DEP-SC GIP Benefits.xlsx". A note in cell A8 reads "NOTE: Miles of UG to be Installed Equals 2x the OH Miles". Indeed, column M ("Miles of UG to be Installed") is approximately double column B ("Original Target PH Miles").
a. Please explain why the UG miles would be double the OH miles.
b. Please explain the cost implications of this note. Does the note mean the cost to underground one mile of overhead line is $1.7 million, not $850,000?
c. Does the noted ratio – two miles UG for every one mile of OH – apply to the entire proposed targeting undergrounding program and Oliver testimony workbook "TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx"?

Response:

Assuming the question meant column K ("Miles of UG to be Installed"), not column M ("Incidents Prevented by TUG"), then you are correct that the number of UG miles in the referenced spreadsheet is calculated to be 2 times the targeted OH miles.
a. In order to calculate the projected benefits for TUG in SC the Company needed to estimate the amount of UG miles to be installed. Without a detailed design for all projects we used the engineering assumption that the radial overhead line would be replaced with a looped UG system (for operational & reliability reasons) which would equate to 2 times the length of the OH mileage.
b. There are no cost implications associated with 6-4 a. as the unit cost of $850,000 is based on historical actuals.
c. No. The TUG DEC-DEP CBAs use a 1-to1 ratio.

Stephens Exhibit -7

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 8

Docket No. E-7, Sub 1214

Date of Request: January 31, 2020
Date of Response: February 10, 2020

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The attached response to NCJC Data Request No. 8-34, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning and Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

8-34. Refer to DEC's response to NCJC DR 5-39, and to Oliver testimony workbook "HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx."
a. Are the transformers and secondary lines downstream of those transformers to which the retro fits are planned presently operating safely and reliably?
b. Are retrofits planned for "Completely Self Protected" (CSP) transformers in this program? Identify the number of CSP transformers DEC proposes to apply retrofits to, and explain the logic of these replacements.
c. Provide any and all Cost Benefit Analyses that shows that the CMI minutes associated with faults occurring "at or downstream of the distribution transformer planned for retrofits" justifies the cost of these replacements.
d. Provide the number of outages that have occurred on the transformers and secondary lines that are planned for transformer retrofits.
e. Provide any and all instances of voltage problems associated with the equipment that is proposed for transformer retrofits.
f. Provide the number of outage complaints that Duke has received associated with the transformers proposed for retrofits.
g. Provide a list of the outages that have occurred in the past five years directly associated with incidents "at or downstream of" the transformers proposed for retrofits.

Response:

a. Current distribution transformers and secondary lines downstream of those transformers to which the retro fits are planned are operating safely.
b.
i. Yes.
ii. The population of CSP transformers to be retrofitted is unavailable.
iii. All overhead transformers that do not have a primary fuse at the transformer, covered primary lead wire, wildlife protectors on the arrester & primary bushing, and a modern arrester mounted on the transformer are targeted for retrofit. A sustained fault on the primary side of a CSP transformer will cause the upstream fuse, recloser, or circuit breaker to lock out causing a sustained outage for significantly more customers than necessary.
c. See the Transformer Retrofit CBA for CMI data for un-retrofitted transformers.
d. See the Transformer Retrofit CBA for the number of outages due to un-retrofitted transformers.
e. This data is not available at the transformer level

f. This data is not available at the transformer level
g. This data is not available at the transformer level. See attached spreadsheet titled “DEC NCJC DR 8-34 g. Number of Outages Due To Unretrofitted Transformers (2015 - 2019) including MEDs”.

DEC NCJC DR 8-34
g. Number of Outag

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 5

Docket No. E-7, Sub 1214

Date of Request: January 16, 2020
Date of Response: January 27, 2020

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The attached response to NCJC Data Request No. 5-40, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analyst, Distribution Finance – Carolinas, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

5-40. Refer to Oliver Exhibit 10, page 23, "Distribution Transformer Retrofit", which states "The core activities of the transformer retrofit program include the installation of a fuse disconnect device on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer. In addition, through protective device coordination, the local fused disconnect can be set to prevent any upstream operations of reclosing devices (the source of momentary outages for customers not served by the retrofitted transformer)."
a. Explain why Duke would have a "Fast Trip" on an upstream device to save fuses downstream, then install a fuse device on "the high-voltage side of every overhead transformer" location to override the upstream setting. Is that not defeating the purpose of the fast trip, to eliminate fuses blowing because of faults caused by tree limbs or squirrels on transformers?
b. Confirm that eliminating the "fast Trip" settings on the upstream devices eliminates the need for these individual high side transformer fuse devices. If this cannot be confirmed, please explain.
c. A key value proposition of both the Self-Optimizing Grid and the Targeted Undergrounding program is the minimization of momentary outages. If the distribution transformer retrofit program is designed to minimize momentary outages, and is deployed to every overhead transformer, explain how momentary outage reduction benefits can be attributed to all three programs simultaneously without double or triple counting benefits.

Response:
a. The Transformer Retrofit Program is designed to reduce the number of faults that occur on distribution transformers (by the addition of wildlife protection, covered lead wire, working lightning arrester installed on the transformer) and mitigate the number of customers impacted by any faults that do occur on the transformer (the addition of a fuse disconnect on the high-side of the transformer/lightning arrester). An ancillary benefit is that the current limiting component of the transformer fuse is fast enough to reduce the number of momentary operations by an upstream reclosing device when the fault is at the transformeritself. The Fast Trip of the upstream reclosing device is still needed to appropriately respond to temporary faults that will still occur anywhere on the system between the transformer fuse and the upstream reclosing device. The Fast Trip also limits the damage to system component by reducing the time they are exposed to thru-faults.
b. As stated in the response to a. above the Fast Trip setting on the upstream reclosing device is still needed to appropriately respond to temporary faults that may occur anywhere between the transformer fuse and the upstream reclosing device. Even if we

removed the Fast Trip settings from the upstream reclosing device, we would still need the transformer fuse to address the primary goals of transformer retrofit to mitigate the number of customers impacted by a sustained fault at the transformer.

c. Momentary benefits from Transformer Retrofit and Targeted Underground are not duplicated because we will not retrofit overhead transformers in the areas that are currently targeted to be converted to underground. Momentary benefits from Transformer Retrofit and Self-Optimizing Grid are not duplicated because the momentaries associated with Transformer Retrofit are only those caused by faults that occur on the transformer. The momentary benefits for SOG are associated with the outages that occur on the 3-phase switchable segments of the circuit.

Stephens Exhibit -9

Duke Energy Carolinas
Response to
NCJC Data Request
Data Request No. 2

Docket No. E-7, Sub 1214

Date of Request: December 30, 2019
Date of Response: January 9, 2020

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The attached response to NCJC Data Request No. 2-4, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

2-4. Please refer to DEC's response to NCSEA DR 2-19, which indicates that the physical security of 11-13 substations will be upgraded annually at a cost of $4.2 million each. Provide a rough split of this $4.2 million budget for each the substation components listed in DEC's response to NCSEA DR 2-19:

a. High-security perimeter fencing;
b. Intrusion detection/cameras/lighting;
c. Pre-fab security equipment enclosure building;
d. Hardening of existing control houses.

Response:

a) $2.0M
b) $1.2M
c) $0.8M
d) $0.2M

Stephens Exhibit -10

Duke Energy Carolinas
Response to
North Carolina Sustainable Energy Association Data Request
Data Request No. NCSEA 2

Docket No. E-7, Sub 1214

Date of Request:	**November 18, 2019**
Date of Response:	**November 25, 2019**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 2-19, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analyst, Distribution Finance - Carolinas, and was provided to NCSEA under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

19. Refer to Oliver Exhibit 10, page 91, which lists the 3-year budgets for Substation Physical Security at $110.7 million.
a. Provide a complete description and detail behind the $110.7 million capital budget, including the types of assets to be installed, the costs and counts of each asset type, the identities of the substations selected, types of unauthorized intrusions to be avoided by the assets to be installed, etc.
b. Provide a list of unauthorized intrusions experienced in DEC or DEP substations in the last 10 years, as well as the consequences associated with each intrusion.
c. Provide a list of all DEC and DEP substations in North Carolina, along with a list of circuits associated with each and count of customers served by each circuit.

Response:

a. The Physical Security program provides security enhancements including demolition of existing perimeter fence and foundations to install a high security perimeter fence with intrusion detection, and lighting, and cameras. The high security perimeter fence is an anti-cut, anti-climb fabric with animal protection to delay and deter intrusion from unauthorized person and/or animals that may cause harm to the substation equipment. The intrusion detection and cameras located on the perimeter fence are to monitor and detect an unauthorized person is trying to cut, climb or enter the substation. Cost includes the installation of prefab security enclosure building for all security components, hardening of existing control house with 3-point locking system and forced-entry doors.
DEC plans to address security concerns at approximately 11-13 locations in NC and SC over the next 2 years at an estimated average cost of $4.2 million per site (NC allocated cost)
Sites and estimates may be revised over this timeframe as physical security needs dictate. Due to the sensitive nature of these projects, further details surrounding the intrusion detection prevention capabilities and cost breakdown with project scope is not provided.

b. None.

c. Please see attached Excel document NCSEA DR-2-19. The first tab is the list of substations, the 2nd is the list of circuits attached to each substation along with customer counts by circuit.

NCSEA
Data Request No. 2
DEC Docket No. E-7, Sub 1214
Item No. 2-19

b. None.

c. Please see attached Excel document NCSEA DR-2-19. The first tab is the list of substations, the 2nd is the list of circuits attached to each substation along with customer counts by circuit.

NCSEA DR-2-19.xlsx