BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Utility	**)**
Service in North Carolina	**)**

DIRECT TESTIMONY OF CAROLINE GOLIN ON BEHALF OF NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND EMPLOYER.

A. My name is Caroline Golin. I am the Southeast Regulatory Director for Vote Solar.

Q. PLEASE STATE YOUR EDUCATIONAL AND OCCUPATIONAL EXPERIENCE.

A. I received my PhD in Energy Policy from the Georgia Institute of Technology along with my Masters in Civil Engineering. I have authored over thirty research papers and reports related to grid investment, rate design, the use of distributed resources to achieve localized distribution planning objectives, renewable energy policy, resource planning, and policies to support the efficiency and effective use of distributed energy resources. I have also testified or prepared reports relating to grid investment, distributed energy resource planning, utility financial analysis, and the costs and benefits of renewable energy, in or related to cases before public utility commissions in Georgia, South Carolina, Ohio, Florida, Kansas, Massachusetts, Rhode Island, and North Carolina. My full CV is provided as Exhibit CG-1 to this testimony.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of North Carolina Sustainable Energy Association ("NCSEA"), an intervenor in this proceeding.

Q. HAVE YOU PREVIOUSLY TESTIFIED IN FRONT OF THE NORTH CAROLINA UTILITIES COMMISSION?

A. Yes. I submitted direct testimony in Docket No. E-2, Sub 1142, related to Duke Energy Progress' Power/Forward proposal.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to appraise the Power/Forward (herein "P/F") proposal put forth by Duke Energy Carolinas (herein the "Company" or "DEC" or "DE Carolinas") and the Company's request to recover Company spending related to the P/F proposal either through the Grid Reliability and Resiliency Rider (herein "GRR") or through deferment into a regulatory asset. From my evaluation, I will make specific recommendations to the Commission regarding the need for a separate regulatory process to appraise the Power/Forward investments and also the future of rate design in North Carolina.

Q. WHAT INFORMATION DID YOU REVIEW IN PREPARING THIS TESTIMONY?

A. I reviewed relevant pre-filed testimony of Company witnesses, filed Company presentations and tables, and relevant Company responses to information requests submitted by NCSEA and other parties to this proceeding. I also reviewed relevant Company shareholder and investor presentations related to the Power/Forward plan and all public Company communications regarding the Power/Forward plan. Additionally, I reviewed grid modernization proposals in other jurisdictions.

Q. WHAT ARGUMENTS DO YOU MAKE IN YOUR TESTIMONY?

A. In my testimony, I argue the following primary points:

1. The P/F proposal is an unjustified and irresponsible investment proposal and is not in the best interest of ratepayers. The P/F proposal is not an investment in a modern grid but that will provide minimal, direct benefits to the ratepayer in exchange for significant increase in rates.
2. The economic analysis put forth by the Company to legitimize the P/F proposal is flawed, exaggerates the economic benefits of the P/F, and indefensibly fails to support the P/F proposal.
3. The engineering and operational justification put forth the by the Company for the P/F proposal and the individual program investments is insubstantial, opaque, and in some cases foundationless.
4. The P/F proposal, in combination with other proposals presented by the Company in this rate case, are representative of a major shift in the business investments and operations of the electric industry in North Carolina and such a shift holds negative implications for the long-term prudency of rate design and the authority of the North Carolina Utilities Commission. The Company's current proposal for cost recovery for P/F through the GRR, in concert with its approach to the Minimum System Method and massive shift towards investments in the distribution system, establishes a pathway towards even higher fixed charges and a loss of customer control.
5. The Company's approach to grid investment is contrary to the policy approaches taken in other jurisdictions. Specifically, the Company's failure to conduct robust cost benefit analysis, the failure to include any stakeholder

input, and the failure to set clear and measurable goals each fly in the face of the standard policy approaches taken in other jurisdictions.

Q. WHAT IS YOUR RECOMMENDATION TO THE COMMISSION?

A. Based on my review of the evidence in this case, I make the following recommendations:

1. I recommend that the Commission deny the Company's proposal to recover investment costs related to the P/F proposal through either the GRR or by deferment into a regulatory asset request because the P/F proposal is not a prudent use of customer monies.
2. If the Company chooses to move forward with developing a plan to modernize the distribution system, it should do so with greater care and thought. To that end, the Commission should open a separate, generic proceeding to thoughtfully and thoroughly plan for the future of the electric grid in North Carolina. The proceeding should be conducted in conjunction with a commission or staff-directed stakeholder process. The stakeholder process should culminate in the production of a robust study, performed by an independent third-party that examines multiple pathways for modernizing the grid. Additionally, the Commission could utilize the proceeding and the stakeholder engagement as an opportunity to determine whether the traditional business model is appropriate for capital expenditures regarding grid services generally, whether the traditional application of the "used and useful" standard to assess the prudence of

capital investments is applicable for the proposed Power/Forward plan specifically, and the implications that such a standard may hold for the future of rate design. I strongly urge the Commission to consider opening a docket or stakeholder working group to examine how to ensure prudent and fair rate structures moving forward.

3. I support the approach proposed in S.B 619 and recommend that the Commission withhold any judgement on the proposed Power/Forward plan until the General Assembly acts on S.B. 619 or adjourns. From my understanding, proposed Senate Bill (S.B.) 619 contemplates the need for more thorough analysis and seeks to fund:

> "a comprehensive study of known and measurable costs and benefits of grid investment by investor-owned electric public utilities. The study shall include an analysis of the need to enhance and modernize the electrical transmission and distribution grid in the State to ensure an electrical grid that is resilient, secure, capable of meeting future demand growth, and able to integrate new technologies."[1]

Q. WHAT IS THE STRUCTURE OF YOUR TESTIMONY?

A. In Section II, I provide a brief overview of the Company's Power/Forward plan.

In Section III, I examine the economic analysis put forth by the Company to justify the P/F and articulate the negative implications that P/F holds for the economics of the state of North Carolina.

[1] S.B. 619 (JLCEP Study Grid Modernization), 2017-18 Session, *available at* http://www.ncleg net/gascripts/BillLookUp/BillLookUp.pl?Session=2017&BillID=S619&submitButton=Go.

In Section IV, I examine the engineering analysis put forth by the Company to legitimize the need for the P/F and provide an appraisal of the proposed program investments under the P/F, in terms of their validity and their value.

In Section V, I examine the P/F within the context of a larger shift by Duke Energy Corporation and in concert with other proposals put forward in this docket. Specifically, I focus on the negative implication that the P/F proposal and the Minimum System Study hold for the future of prudent rate design, customer control over energy expenditures, and customer welfare in a future of increasing investments in the distribution system.

In Section VI, I compare the Company's approach to grid investment to the best practices of grid investment in terms of the policy processes.

In Section VII, I provide my conclusions and recommendations to the Commission.

II. BACKGROUND ON THE POWER/FORWARD PROPOSAL

Q. PLEASE SUMMARIZE THE COMPANY'S POWER/FORWARD PROPOSAL.

A. The Company's proposed P/F proposal is a ten-year, massive capital investment plan in the transmission and distribution system. The primary goal of the P/F proposal is improving grid reliability. From 2018-2028, the Company is proposing to spend $7.78 billion, with Duke Energy Progress spending an additional $5.4 billion.

Table 1. Provides the total spending for the P/F over the next 10 years.

Undergrounding Powerlines	$4.9 billion
Distribution Hardening	$3.5 billion
Transmission Improvements	$2.2 billion
Self-Optimization	$1.2 billion
Advanced Metering	$549 million
Communications Upgrades	$546 million
Enterprise Systems	$103 million
TOTAL	**$13 billion**

Table 1. 10-year investment for Power/Forward.[2]

The single largest investment category set forth in the P/F proposal is the undergrounding of powerlines, which by 2028, amounts to almost $5 billion dollars.

The first proposed phase of P/F spans from 2017-2021. During this time frame, the Company plans to spend $2.9 billion in capital expenditures and $130 million in O&M.[3] The outlined total spend through 2021 is provided in Table 2.

[2] Duke Energy Carolinas Response to PS DR56-15, embedded PDF Document "PSDR 56-15 Power Forward Carolinas – Executive Technical Overview.pdf" (herein "Power Forward Carolinas Executive Technical Overview") (attached as Exhibit CG-2); *See also* NCUC Docket No. E-2, Sub 1142, Exhibits Vol. 9, p. 46.
[3] Direct Testimony of Robert M. Simpson, III for Duke Energy Carolinas, LLC (herein "Simpson Direct"), p. 23.

DEC Grid Improvement Plan
($ MM)

	Capital				
Program Name	2017	2018	2019	2020	2021
Enterprise Systems	13	30	28	18	19
Communication Total	0	25	32	33	30
Transmission Total	46	120	138	165	165
Self-Optimizing Grid	10	59	94	94	94
Targeted UG	-	19	158	258	435
Distribution Hardening & Resiliency	**21**	**157**	**201**	**198**	**245**
Total	**90**	**410**	**651**	**765**	**987**

Table 2. Planned Capital Investments of the Power/Forward[4]

The single largest investment category for the first installment of the P/F proposal is the undergrounding of powerlines which will total $870 million by 2021.

Specific to this rate case, in 2018, the Company is proposing to spend $670 million in capital investments, with $290 million in distribution investments and $120 million in transmission investments, and $21 million in Operations & Maintenance (O&M) expenses, with $19 in distribution O&M and $2.3 million in transmissions O&M. The proposed spending is broken out into the following categories, with the following 2018 price tags:

- **<u>Advanced Metering Infrastructure (“AMI”).</u>** The Company is targeting full deployment of AMI for its customers. The Company proposes to spend $155 million on AMI in 2018.

[4] *Id*. at p. 38.

- **Enterprise Systems Upgrades.** The Company is proposing investment in back-office systems to improve the operation and management of the grid. The only concrete example the Company has provided in this category is an investment in a Distribution Management System ("DMS"). A DMS receives and analyzes data captured on thousands of sensors and automated switches. DMS can enable automated fault location and service restoration which reduces manual intervention. The Company proposes to spend a total of $30 million on enterprise system upgrades in 2018, however no exact numbers have been provided regarding how that spending will be distributed among technologies.
- **System Intelligence and Communications Uplift.** The Company proposes to invest in automated switches, grid sensors and enhanced communications. No detail on the exact investments have been provided or where the switches and sensors will be placed. The Company proposes to spend $25 million in 2018 on its system intelligence and communications uplift.
- **Transmission Improvements.** The Company is proposing investment in substation and transmission line upgrades in capacity, automation, equipment modernization, physical and cyber security, and system intelligence capabilities. Details on these exact investments, where they will be targeted and how much money will be spent have not been provided. The

Company proposes to spend $120 million on transmission improvements in 2018.

- **<u>Distribution Hardening and Resiliency</u>**. The Company is proposing investment in retrofitting or replacing aged and/or deteriorating cable and conductors; updating physical and cyber security; improving capacity margin, and providing back feed capability to vulnerable communities. Again, details on these exact investments, where they will be targeted and how much money will be spent have not been provided. The Company proposes to spend $157 million in this category in 2018.
- **<u>Targeted Undergrounding.</u>** The majority of DEC's proposal is to invest in undergrounding of power lines. The Company proposes to target lines that have a disproportionate amount of momentary interruptions and outage events first. The Company proposes to spend $19 million for undergrounding in 2018 and a total of $870 million over the next four years.
- **<u>Self-Optimizing Grid</u>.** The Company is proposing to invest in added capacity in distribution circuits and substation transformers as well as connecting radial distribution circuits together with automated switches. This will be supported by the proposed Distribution Management System. The Company has not provided any details on these exact investments, where they will be targeted and how much money will be spent on which portions of the grid. The Company proposes to spend $59 million on self-optimizing grid investments in 2018.

Q. IS THE POWER/FORWARD PROPOSAL THE TOTALITY OF THE PROPOSED INVESTMENT IN THE TRANSMISSION AND DISTRBUTION ("T&D") SYSTEM FOR THE COMPANY?

A. No. In addition to the P/F proposal, the Company plans to spend $3.4 billion over the next four years on customary investments in the transmission and distribution system.[5]

Q. IS THIS IN LINE WITH THE COMPANY'S HISTORICAL EXPENDITURE ON THE T&D SYSTEM?

A. No. From 2008-2016, the Company's average total spend on capital investments in the T&D system was $568 million. Moving forward, the Company plans to spend on average $850 million or a 50% increase in spending. When combined with the P/F investments, the Company is proposing to spend over $1.6 billion annually just in capital investments for the T&D system. This represents a 55% increase in the capital expenditures on the T&D system.[6]

Q. IS THERE OVERLAP BETWEEN THE PROPOSED $3.4 BILLION INVESTMENT IN THE T&D AND THE P/F PROPOSAL?

A. Yes. The types of investments proposed under the P/F proposal overlap with the customary spend but are additional to the customary spend.[7] For example, the $3.4 billion includes capacity increases to distribution circuits and substations for load growth. The P/F proposal also includes investments in capacity increases. The

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[5] Duke Energy Carolinas, LLC Response to Tech Customers Data Request No. 2-7.
[6] Duke Energy Carolinas, LLC Response to Tech Customers Data Request No. 2-11 (attached as Exhibit CG-3).
[7] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 4-5 (attached as Exhibit CG-4).

customary spend includes investments in "hardening and resiliency", such as transformer retrofits, deteriorated conductor replacement, and circuit sectionalization.

Q. IS IT CLEAR HOW THE COMPANY WILL DELINEATE BETWEEN CUSTOMARY SPEND AND P/F SPEND?

A. No. There are some investments, namely undergrounding powerlines that have been earmarked for P/F and the GRR rider. However, as I will outline later in my testimony, the Company has also redefined elements of its minimum system study to allow for the undergrounding of powerlines to be recouped through the Customer Connect Charge. In regards to all other P/F investments, the Company has not made clear why some investments fall under normal rate recovery and other investments fall under the GRR. The Company has only stated that it will assign a separate "routine and GRR Rider installation by aligning the scope and work plans associated with each to distinct accounting code block that captures these costs separately, where practical."[8]

The Company has also failed to delineate a clear decision-making procedure for how it determined which capital investments are routine and which investments fulfill the goals of the P/F proposal. This is evident by the fact that, before the P/F proposal was made, the estimated customary spend on T&D was $4.5 billion. After the P/F proposal was made, the Company transferred $1 billion dollars of proposed

[8] Duke Energy Carolinas, LLC Response to Tech Customers Data Request No. 2-9 (attached as Exhibit CG-5) (herein "Tech Customers 2-9").

customary spend and redirected it to the P/F proposal and the proposed cost recovery through the GRR.[9]

III: ECONOMIC JUSTIFICATION FOR THE P/F PROPOSAL AND THE IMPACT OF THE P/F PROPOSAL ON NORTH CAROLINA'S ECONOMY

Q. WHAT ECONOMIC ARGUMENT IS THE COMPANY MAKING TO SUBSTANTIATE THE P/F PROPOSAL?

A. The Company claims that in the face of growing population more investments are needed in the grid to maintain reliability and maintain customer satisfaction since customers are demanding "perfect power." The Company claims that the P/F proposal will "provide significant reliability improvements" and "stimulate approximately $33 billion in economic growth for the state of North Carolina." [10]

Q. CAN YOU PLEASE DETAIL WHAT "PROVIDE SIGNIFICANT RELIABILITY IMPROVEMENTS" MEANS FOR THE AVERAGE CUSTOMER?

A. The Company estimates that the proposed P/F program will improve the reliability of power by 40-60%, compared to customary planned spend, represented by a 40-60% improvement in SAIDI scores.[11] This means that without the P/F's $13.8 billion investment strategy, then SAIDI will degrade from 163 minutes per customer to 225 minutes per customer in 2028.[12] In real terms, this means that customers who now experience an average of 2.7 hours of lost power per year,

[9] Tech Customers 2-9.
[10] Power Forward Carolinas Executive Technical Overview, p. 1.
[11] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 8-12 (attached as Exhibit CG-6).
[12] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 8-11 (attached as Exhibit CG-7).

would experience an average of 3.7 hours of lost power per year within the next ten years if the P/F program is not initiated.

Q. WHAT ARE THE ESTIMATED IMPACTS, OR THE COSTS, OF THE P/F PROPOSAL OVER THE NEXT TEN YEARS?

A. The Company has not provided a clear, public estimate of the rate impacts of the P/F proposal or the GRR over the next ten years. Despite requests from NCSEA,[13] the Company has not estimated the total impact on rates from the GRR or the P/F proposal beyond the 2018 test year. I find this concerning because the economic analysis contracted by the Company made assumptions about rate impacts. Even more troubling, while the Company was able to give a clear projection of shareholder profit projections resulting from the P/F proposal, it was not able to provide a clear projection of the rate impacts.

From a simple appraisal of the 2018 GRR, if carried out through 2021, the GRR will cost the average residential customer between $225 and $300. If carried out through 2028, just the GRR will cost the average residential customer between $530-720.[14] I stress that these estimates only account for the GRR and do not take into account the full cost of P/F once all capital investments are placed into rate base, substantially increasing rates.[15]

[13] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 9-10.

[14] Assuming the same distributional break down provided in Direct Testimony of Michael J. Pirro for Duke Energy Carolinas, LLC (herein "Pirro Direct"), Direct Exhibit No. 9, and assuming an average energy use between 12,000-15,000 kWh annually.

[15] These estimates are in line with Company-provided Ernst & Young ("EY") analysis that the P/F proposal will raise customer rates by over 20% through 2026. North Carolina Impacts of Duke Energy's Power/Forward Grid Improvement Program. *See* Duke Energy Carolinas Response to PS DR56-15, embedded PDF Document "PSDR 56-15 EY QUEST Duke Energy NC PowerForward Impact.pdf" (attached as Exhibit CG-8) (Exhibit CG-8 known herein as "EY Analysis Exhibit").

Additional estimates on the rate impacts of P/F, including estimates given by the Company in closed meetings, have placed the upward pressure on rates from P/F at 4.31% year over year. Over for the next 10 years, this translates to a 52% increase in rates for the residential customer class or an average of $3,792.[16]

Q. FROM YOUR PERSPECTIVE, IS A MINIMUM INCREASE OF OVER 20% IN RATES JUSTIFIED TO AVOID AN AVERAGE INCREASE IN 1 HOUR OF RELIABLE POWER PER YEAR?

A. From my perspective, the increase in electric bills by 20-50% is not offset by the potential benefit of avoiding one hour of additional power service interruptions.

Q. HOW DOES THE COMPANY SUBSTANTIATE THEIR CLAIM THAT P/F WILL "SIMULATE APPROXIMATELY $33 BILLION IN ECONOMIC GROWTH FOR THE STATE OF NORTH CAROLINA?"[17]

A. In a cursory attempt to run a cost/benefit analysis on the proposed P/F program, the Company contracted EY to assess the benefits of avoided customer outages and an increase in economic activity from P/F spending. EY conduced two analyses. The first was an appraisal of the direct and indirect job impacts of the P/F program. For this analysis, EY used the IMPLAN model. Building off the IMPLAN analysis, EY then analyzed how a potential improvement in reliability may produce economic benefits to the NC economy. For this analysis EY utilized the Regional Economic Models, Inc. ("REMI") model to assess the macro economic benefits of the P/F

[16] Direct Testimony of Kevin W. O'Donnell, CFA on Behalf of the Carolina Utility Customers Association, Inc., pp. 12-13.
[17] Power Forward Carolinas Executive Technical Overview, p. 1.

proposal. This EY analysis started from the assumption that P/F would improve reliability by 40-60%, estimated the economic value of improved reliability using the US Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") Calculator, and then translated these potential marginal improvements in reliability metrics (using the REMI model) into benefits for businesses and households[18].

Q. HAVE YOU READ THE ANALYSES BY EY AND DO YOU BELIEVE THAT THEY SUBSTANTIATED THE COMPANY'S CLAIM THAT P/F WILL PRODUCE SIGNIFICANT ECONOMIC GAINS IN NORTH CAROLINA?

A. I have reviewed both analyses (collectively the "EY analysis") and find that they are deeply flawed and grossly misleading. They fail to substantiate the Company's claim that P/F will produce significant economic gains to the state.

Q. CAN YOU PLEASE EXPAND UPON YOUR CONCERNS WITH THE EY ANALYSIS?

A. While I find multiple issues with the EY analysis, I will focus on the four most egregious errors:

- First, the EY analysis grossly overestimates the economic impact of reliability to the NC economy. EY estimates that 135 minutes of economic output (due to improved reliability) for North Carolina is valued at $1.7 billion in 2028.

  "The anticipated benefit of the reliability improvement (in terms of avoided outage-related business costs) will range from $29 million

[18] *See* EY Analysis Exhibit.

> in 2018 to $1.67 billion by the end of 2028, including $1 billion related to normal-service reliability and $670 million related to avoided MED outages."[19]

I find this assumption to be absurd. To put this into perspective, in 2016, the North Carolina GDP was $521.6 billion, which, on average, equates to $992,390 per minute. At $992,390 per minute, 135 minutes equals $744 million. Following EY's logic, the Company is claiming that the economic damages, from lost economic activity and the start-up costs, of a power outage to the North Carolina economy is 13 x greater than the entire economic activity of North Carolina had there never been outage in the first place.

- Second, all of EY's assumptions on the economic value of reliability were built on indefensible assumptions and outdated data.
- Third, the EY analysis fails to take into account how a 20% minimum increase in rates impacts the competitiveness of North Carolina's economy, the impact to the labor market, and business investment.
- Fourth, I take issue with the fact that the overwhelming majority of economic benefits are qualified in job creation and wages.

Q. CAN YOU PLEASE EXPAND ON HOW EY ESTIMATES THE ECONOMIC VALUE OF RELIABILITY IMPROVEMENT?

A. EY estimates that reliability improvements for regular service and major events could result in $1.67 billion in avoided costs annually for North Carolina businesses

[19] *Id*. at p. 18.

and households once the project is complete in 2028.[20] EY determined this value using data from Duke Energy as inputs to the US Department of Energy's ("DOE") Interruption Cost Estimate ("ICE") Calculator, which uses an econometric model to estimate the cost to businesses and households of electricity service interruptions.[21] EY explains that the avoided outage cost benefits calculated in ICE Calculator are driven by savings to business customers, not residential customers.[22]

Q. IS THE EY ANALYSIS REASONABLE FOR ASSESSING THE CURRENT OUTAGE COSTS OR NORTH CAROLINA RATEPAYERS' DESIRE AND WILLINGNESS TO PAY FOR IMPROVED RELIABILITY?

A. No. EY acknowledges a fundamental flaw in the ICE Calculator, stating:

> (The ICE Calculator uses) data from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005 … The primary limitations of the ICE Calculator stem from the data used to fit the underlying model. In particular, about 50% of the data available was more than 15 years old as of 2015[23].

Q. DOES THE ICE CALCULATOR UTILIZED BY THE COMPANY INCLUDE THE INTERRUPTION COST DATA FOR THE COMPANY'S CUSTOMERS?

A. Customer interruption costs survey results from Duke Energy were included in the original version of the ICE Calculator released in 2011.[24] However, the data

[20] *Id*. at p. 4.
[21] *Id*. at p. 28.
[22] *Id*. at p. 22.
[23] *Id*. at p. 28.
[24] The initial meta-analysis and report regarding ICE was completed in 2009, *see* http://emp.lbl.gov/sites/all/files/lbnl-2132e.pdf, p. i., but the ICE Calculator was initially released in July 2011. *See* https://www.osti.gov/scitech/servlets/purl/1172643.

included was from a Duke Energy customer survey conducted in 1997 or possibly even as far back as 1990.[25]

Q. HAS THE ICE CALCULATOR BEEN UPDATED SINCE 2009?

A. Yes, the DOE and its advisors updated the ICE Calculator in 2015 and included 2011 interruption cost survey results from one of the "Southeast" utilities[26]. Although I am unable to definitely confirm the identity of this utility, I strongly suspect it is not DE Carolinas. Otherwise, the Company would have logically used these more recent customer survey results rather than relying on data that is at least 20 years old.

Q. DOES THE ICE CALCULATOR ACCURATELY REFLECT CURRENT INTERRUPTION COSTS FOR THE COMPANY'S CUSTOMERS?

A. No, I do not believe that data contained in the ICE Calculator accurately reflects the current interruption costs for DE Carolina's customers. Furthermore, customers that have critical loads, high outage costs, and require uninterrupted service (e.g., data centers, hospitals, some manufacturers, etc.) have likely already invested in backup power supplies or self-generation. These customers will see minimal benefit from improvements to the Company's system reliability.

Q. IS THERE A BETTER WAY TO DETERMINE CUSTOMER INTERRUPTION COSTS FOR THE COMPANY'S CUSTOMERS?

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[25] This assumes that the Company is one of the three "Southeast" utilities included in the analysis conducted by the Department of Energy titled, Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States, *see* https://www.osti.gov/scitech/servlets/purl/1172643, pp. 16-17.
[26] *Id*.

A. Yes. The preferred method for estimating customer interruption costs, as the Company apparently applied between 1990 and 1997, is a survey that describes several hypothetical interruption scenarios and asks a representative sample of residential, commercial and industrial customers to detail the costs that they would experience under those conditions[27]. Although this approach can be time-consuming, it is important for a program of the magnitude of Power/Forward to utilize accurate customer outage costs in a robust cost/benefit analysis.

Q. DOES THE EY ANALYSIS ACCOUNT FOR THE FULL COST OF P/F ON THE NORTH CAROLINA ECONOMY?

A. No. From my review, the EY analysis only accounts for the direct cost of the P/F via direct rate increases, but does not account for induced impact of increased electricity rates on all aspects of the NC economy including, but not limited to: raises in property taxes as public school operating expenditures increase; raises in medical bills as hospital and clinics operating expenditures increase; raise in tithes as churches' operating expenditures increase; increases in the operating costs of commercial business and manufacturing. Furthermore, from my review, the EY analysis only accounts for rate impacts through 2026, while still counting benefits beyond 2028, and does not account for rate impacts of the final two years of the P/F investments. This mismatch greatly skews the comparison of costs and benefits.

Q. ACCORDING TO THE EY ANALYSIS, HOW DOES THE DISTRIBUTION OF BENEFITS FROM P/F COMPARE BETWEEN RESIDENTIAL

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[27] http://www.nexant.com/resources/using-customer-reliability-benefits-assess-grid-modernization-priorities.

RATEPAYERS (HOUSEHOLDS), IN TERMS OF AVOIDED CUSTOMER OUTAGE COSTS, WITH THE BENEFITS THAT ACCRUE FROM INDIRECT ECONOMIC ACTIVITY?

A. From the EY analysis, if implemented, P/F will not result in any meaningful, direct benefits to households. Of the total benefits, 3% accrue to households, in the form of cost savings from outages, with the rest of the supposed benefits attributed to indirect economic activity.[28] Even the cited 3% benefit is an overestimate as that estimate is based on faulty logic and includes the benefit of increased reliability from the full investment portfolio but excludes the rate impacts from the last two years of investment.

Q. WHICH CUSTOMER CLASS STANDS TO RECEIVE THE MOST BENEFITS FROM THE IMPLEMENTATION OF THE P/F PROPOSAL?

A. While I am not certain that any customer class will actually see a net benefit from the P/F, the customer classes that will receive almost all of the benefits based on the EY analysis are the commercial and industrial customers. [29]However, I believe even these benefits are dwarfed by the potential rate impacts and cost of business.

Q. BUT DON'T LARGE COMMERCIAL AND INDUSTRIAL CUSTOMERS ALREADY PAY FOR INCREASED RELIABILITY?

A. Yes. Commercial and industrial customers already pay for reliability and have been increasingly investing in distributed generation, in the form of solar and battery

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[28] EY Analysis Exhibit, p. 20
[29] *Id*. at p. 19

storage, as a source of back-up power over the past 15 years, including in North Carolina.[30]

Q. THE COMPANY ALSO CLAIMS THAT THE P/F PROPOSAL IS JUSTIFIED BECAUSE IT MUST SATISFY CUSTOMERS' DEMAND FOR "PERFECT POWER." DO YOU AGREE WITH THIS CLAIM?

A. No. First, as Company Witness Fountain explained, customer satisfaction is already high and improving for DE Carolinas. He stated:

> The most recent results of the industry's key benchmarking study – the 2017 J.D. Power Electric Utility Customer Satisfaction Study – published in July 2017, found DE Carolinas recognized as among the most improved in this year's study, up 52 points vs. 2016, or an increase of 5.2%. The utility industry, by comparison, was only up 39 points or 3.9% … In addition to our relationship study, DE Carolinas utilizes Fastrack, the Company's proprietary transaction study, to measure overall customer satisfaction with our operational performance …Through mid-2017, roughly 85 percent of Duke Energy Carolinas residential customers express high levels of satisfaction with these key service interactions (Start/Transfer Service, Outage/Restoration, Street Light Repair, etc.).[31]

Furthermore the J.D. Power Electric Utility Customer Satisfaction Study found that 28% of overall satisfaction score was related to Power Quality and Reliability.[32] Even if that statistic is representative of all customers, it is not the correct statistic to justify P/F investments. Rather, customers should rate their willingness to pay for marginally improved power quality and reliability over their current level of energy expenditures. More simply, customers were not asked if

[30] NREL, Battery Energy Storage Market; Commercial Scale, Lithium-ion Projects in the U.S. October, 2016. https://www.nrel.gov/docs/fy17osti/67235.pdf.
[31] Direct testimony of David B. Fountain, Docket No. E-7, Sub 1146, pp. 33-34
[32] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 8-10.

they would be willing to increase their bills by 30-50% for marginal improvement in power quality (as proposed in P/F) but merely whether power quality and reliability are important to them. I also disagree that all customers demand "perfect power." As I stated previously, the limited amount of customers that truly require uninterrupted service invest in backup supply in anticipation of periodic outages from their utility.

Q. CAN YOU EXPAND ON YOUR CONCERNS OVER THE FOCUS ON JOBS AS AN ECONOMIC JUSTIFICATION FOR P/F?

A. As a researcher who has used the IMPLAN model before, I understand the mechanics of how IMPLAN works and what the EY analysis is characterizing as "job creation" is not really a creation of jobs but rather a transfer of jobs within the marketplace. The EY analysis fails to articulate the sectors within the economy that will lose jobs due to the P/F proposal. More importantly, as an expert in rate design, I take issue with equating job creation to prudent rate design. Job creation is an important benefit to consider in determining an economic investment strategy for the state of North Carolina, but I do not think that the prudency of an investment proposal by a regulated utility should be assessed based solely on its ability to create jobs as DEC seeks here. Job creation is a benefit that may be taken into account weighing the tradeoffs between two similar investment options with similar costs and benefits. From my understanding, job creation is not considered as an aspect the "used and useful" standard, as that concept is used throughout the country. Ratepayers do not assess their electricity bills based on the number of linemen each kWh purchase supports. There is no line item for the types of benefits that DEC claims offset its certain rate increase. Ratepayers will only recognize the increase.

Q. FROM YOUR EXPERIENCE WITH THE IMPLAN MODEL, HOW WILL THE POTENTIAL JOB CREATION PORTION OF P/F AFFECT THE STATE ECONOMY?

A. The EY analysis assigns the P/F proposal a jobs multiplier of 1.9.[33] This multiplier is on-par with the economic impact of a shopping mall.[34] Essentially, the P/F proposal suggests a similar positive impact on the North Carolina economy as opening a handful of department stores.

Q. FROM YOUR PERSPECTIVE, WOULD THE P/F PROPOSAL PASS THE CONVENTIONAL RATE MAKING TESTS OFTEN EMPLOYED BY UTILITIES TO ESTIMATE THE PRUDENCY OF AN INVESTMENT?

A. No. If assessed against a Ratepayer Impact Measure test, a Participant Cost Test, or even a Utility Cost Test, the P/F proposal would not pass. This is because the P/F proposal projects an upward pressure on rates, not offering any tangible benefits to the customer, and also increasing the overall expenditure for the utility.

Q. ARE THERE ANY OTHER COMMENTS YOU WOULD LIKE TO MAKE REGARDING THE ECONOMIC JUSTICATION OR REASONABLENESS OF THE P/F PROPOSAL?

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[33] EY Analysis Exhibit, p. 3.
[34] https://www.nrc.gov/docs/ML1224/ML12243A398.pdf.

A. Yes. Beyond the egregious failures of the economic analysis used to justify the P/F proposal and the glaring issue of using indirect benefits to non-ratepayers as synonymous with prudent rate design, I think it is important for the Commission to consider the reasonableness of the P/F proposal in terms of a customer's willingness to pay for an investment. As outlined by NCSEA's witness Justin Barnes, the Commission must examine whether the proposed service that P/F provides, which is a marginal improvement in reliability, is proportionate to the cost, which is at minimum a 20% increase in rates and deterrent to economic growth in the State.

IV: ENGINEERING JUSTIFICATIONS FOR THE P/F PROPOSAL AND APPRAISAL OF THE PROPOSED P/F INVESTMENTS

Q. OUTSIDE OF THE ECONOMIC JUSTICATIONS THE COMPANY CLAIMS SUBSTANTIATE ITS P/F PROPOSAL, WHAT ARE THE SPECIFIC ENGINEERING OR OPERATIONS BENEFITS THAT THE COMPANY HAS IDENTIFIED FROM THE P/F PROPOSAL?

A. The Company has identified three primary operational benefits from the P/F, including:

- Operations and Maintenance ("O&M") savings
- Decreased environmental footprint[35]
- Enabling ("Distributed Energy Resources") integration

[35] Simpson Direct, p. 31

Q. HOW MUCH O&M SAVINGS HAS THE COMPANY IDENTIFIED WOULD RESULT FROM THE IMPLEMENTATION OF POWER/FORWARD? ARE THESE SAVINGS SIGNIFICANT?

A. The Company has identified $42 million per year from outage event reduction across North Carolina beginning in year 11[36] and an additional $15 million per year from AMI.[37] These are negligible savings compared to the $7.8 billion price tag for the program.

Q. HOW DOES THE COMPANY CLAIM THAT THE PROPOSED P/F PROGRAM WILL HELP THE COMPANY REDUCE ITS ENVIRONMENTAL FOOTPRINT? DO YOU FIND THIS CLAIM TO BE CREDIBLE?

A. The Company anticipates improved environmental impacts from the reduced risk of oil spills by eliminating oil-filled equipment and reduced risk of avian collisions as a result of undergrounding overhead facilities as set forth in the P/F proposal.[38] Although I am supportive of these potential improved environmental impacts, these positive changes are dwarfed by the negative environmental impact of other elements of Power/Forward. Specifically, the proposed 21 new substations, 2,000 miles of new overhead distribution lines (mostly in rural areas), and thousands of

[36] Power/Forward Carolinas Executive Technical Overview, p.12.
[37] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 3-2.
[38] Power/Forward Carolinas Executive Technical Overview, p. 12.

miles each year of undergrounding distribution lines[39] will significantly increase the Company's environmental footprint.[40]

Q. IF IMPLEMENTED, WILL P/F ENABLE DISTRIBUTED ENERGY RESOURCES ("DER") INTEGRATION?

A. A very small fraction of the P/F proposal to do with DERs. The proposed $103 million Power/Forward Carolinas investment in Advanced Enterprise Systems[41], specifically a Distribution Management System, may enable DER integration. However, this represents 0.8% of the total program cost.[42] Over 99% of the proposed investment will have no impact on the Company's ability to integrate DER. The Company acknowledges this, stating that none of the proposed Power/Forward investments are "specifically intended to accommodate renewables"[43] and the program is "incremental spend focused strictly on reliability."[44]

Q. THE COMPANY STATES THAT INCREASED GRID CAPACITY FROM THE PROPOSED P/F PROGRAM WILL SPECIFICALLY AID IN INTERCONNECTING DER.[45] DO YOU AGREE?

A. Increased grid capacity may or may not aid in interconnecting distributed generation. A circuit's ability to accommodate DG is dependent on multiple factors

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[39] Power/Forward Carolinas Executive Technical Overview, pp. 21-22.
[40] NCSEA requested information on TUG construction methods to try and determine a better understanding of the environmental footprint but did not receive any clear response.
[41] Power/Forward Carolinas Executive Technical Overview, p. 20.
[42] $103 million / $13 billion = 0.8%.
[43] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 2-15 (attached as Exhibit CG-9).
[44] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 2-9 (attached as Exhibit CG-10).
[45] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 4-4.

including the location of the DG, capacity/thermal limits, voltage regulation settings, and system protection settings. To determine the grid's capacity to interconnect distributed generation ("DG") and other DER, utilities must conduct an analysis of each circuit to identify the maximum amount of DER that can be added without violating system constraints. This is commonly referred to as a Hosting Capacity analysis.

Q. HAS THE COMPANY CONDUCTED A HOSTING CAPACITY ANALYSIS OF ITS DISTRIBUTION SYSTEM?

A. No. The Environmental Defense Fund received the following response to a data request:

> The Company does not currently calculate, nor can it estimate, the DER hosting capacity of individual circuits or the grid as a whole. There are several reasons: (1) There is no industry standard that sufficiently defines this term, (2) the calculation for most any definition of this term would be exceedingly complex, and (3) there is no benefit to customers to such an estimation or calculation.[46]

Calculating and publishing circuit hosting capacity is a critical capability for enabling the transition to a modern grid and this response unfortunately reveals the fact that the Company is not committed to DER integration and true Grid investment.

Q. IS THERE AN INDUSTRY STANDARD THAT DEFINES THE TERM "HOSTING CAPACITY"?

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[46] Duke Energy Carolinas, LLC Response to Environmental Defense Fund Data Request No. DR1-9 (attached as Exhibit CG-11) (herein "EDF DR1-9").

A. The Electric Power Research Institute ("EPRI") defines hosting capacity as the amount of DER that may be accommodated on a distribution circuit without degrading reliability and power quality.[47] The concept is widely understood by utility engineers and other experts, and work is underway in many states[48] to calculate hosting capacity and make the results available to customers, DER developers, and other interested stakeholders.

Q. IS THERE A COMMON METHODOLOGY FOR CONDUCTING A HOSTING CAPACITY ANALYSIS?

A. The Interstate Renewable Energy Council ("IREC") recently published a white paper that summarizes four methodologies for conducting hosting capacity analyses.[49] The methodologies range from the most accurate but computationally intensive approach (called the iterative method) to simpler, streamlined methods with less accuracy.

Q. IS HOSTING CAPACITY ONLY RELEVANT FOR STATES LIKE HAWAII AND CALIFORNIA WITH HIGH PENETRATIONS OF DER?

A. No. Hosting capacity analysis is relevant for all jurisdictions committed to transitioning to a modern grid where distributed resources are fully integrated into

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[47] *The Integrated Grid: A Benefit-Cost Framework*, Electric Power Research Institute, February 2015, p. 1-5, available at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002004878.

[48] EPRI's user group is focused on evolving the methodology and application for hosting capacity analysis and has over 25 member utilities, including Southern Company, Entergy, TVA, Xcel Energy, CenterPoint Energy, and American Electric Power.

[49] *Optimizing the Grid – A Regulator's Guide to Hosting Capacity Analysis for Distributed Energy Resources*, Interstate Renewable Energy Council, December 2017, available at: https://irecusa.org/publications/optimizing-the-grid-regulators-guide-to-hosting-capacity-analyses-for-distributed-energy-resources/ (herein "IREC Report").

utility planning and operations as valuable grid resources. For example, the Minnesota PUC has required Xcel Energy to conduct a hosting capacity analysis to guide future DER integration and identify areas of constraint.[50] As part of Rhode Island's Power Sector Transformation, National Grid is required to publish hosting capacity maps to identify system constraints.[51] Pepco Holdings has calculated and published hosting capacity results and is beginning to use the results for streamlining interconnection.[52]

Among other utilities, EPRI has worked with the Tennessee Valley Authority ("TVA") and the 154 local distribution companies it serves to analyze the costs and benefits of integrating solar across its service territory. TVA Vice President of Stakeholder Relations Joe Hoagland stated, "We engaged EPRI to apply their streamlined methods in the Tennessee Valley to further the learning, enabling the efficient analysis of hundreds and thousands of distribution feeders. This has the potential to allow our customers' distribution planners to quickly and accurately assess their own unique systems as distributed generation becomes more impactful at their locations."[53]

Q. IS THE CALCULATION OF HOSTING CAPACITY "EXCEEDINGLY COMPLEX" AS THE COMPANY CLAIMS[54]?

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[50] MN PUC Docket No. E002/M-15-962, June 28, 2016 Order.
[51] *Rhode Island Power Sector Transformation – Phase One Report to Governor Gina M. Raimondo*, Rhode Island Division of Public Utilities & Carriers, Office of Energy Resources, and Public Utilities Commission, November 2017, available at: http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf.
[52] IREC Report, p. 41.
[53] http://mydocs.epri.com/docs/PublicMeetingMaterials/0615/FINAL_Streamlined%20hosting_ig_press_release.pdf.
[54] EDF DR1-9.

A. As I stated previously, there are different methodologies for calculating hosting capacity ranging from simpler, streamlined approaches to more complex and computationally intensive methods. As a company that "strives to be a leader"[55], DE Carolinas should have the expertise and capability within its organization to conduct the analysis, as many other utilities have.

Q. DO YOU AGREE WITH THE COMPANY'S ASSERTION THAT THERE ARE NO BENEFITS TO CUSTOMERS FROM A HOSTING CAPACITY ANALYSIS[56]?

A. No. Understanding the distribution systems' capacity to accommodate DER can help customers and DER developers identify preferred locations for interconnection. Additionally, if the hosting capacity results are applied to streamline the Company's interconnection process, customers will benefit from fewer delays and reduced uncertainty.

Q. WHAT DO YOU RECOMMEND?

A. As part of the new proceeding and stakeholder process for closely examining the Company's proposed Power/Forward plan, the participants should determine the most appropriate methodology and timeline to begin calculating and publishing circuit hosting capacity.

Q. DO YOU HAVE CONCERNS ABOUT THE SPECIFIC PROGRAMS WITHIN POWER/FORWARD?

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[55] Simpson Direct, p. 14.
[56] EDF DR1-9.

A. Yes. I have additional concerns about the most expensive program ($2.7 billion over ten years), the Targeted Undergrounding ("TUG") program. My concerns are related to the TUG prioritization methodology and cost estimates. Additionally, I have concerns about the Company's appraisal of useful life and the Company's failure to assess any other investment alternatives, including the use of DERs.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE TUG PRIORITIZATION METHODOLOGY?

A. The Company has targeted a total of 5,959 miles[57] of overhead conductor to convert to underground, using Events per Target Mile ("ETM") as a prioritization metric. ETM is based on the total number of protective device operations or service or transformer outage events over a ten year period, divided by the length in miles of each targeted circuit segment. The highest ETM value for the targeted circuit segments is 5,514, and any circuit segment with an ETM of 12 or greater is included in the TUG program.

Q. HOW DID THE COMPANY DETERMINE THAT AN ETM OF 12 IS THE APPROPRIATE THRESHOLD FOR INCLUSION IN THE TUG PROGRAM?

A. The Company states:

> Duke Energy's policy regarding proposed TUG candidate targets is to review sites where the distribution overhead infrastructure is at least 50% worse than the average overall overhead performance in faults per mile … DEC NC's distribution overhead averages 0.81 faults per mile. The 12 events per mile for a target segment the question references is the ten year total, which translates to an

[57] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 8-7, Spreadsheet "NCSEA 8-7 DEC NC TUG Request.xlsx", Column V.

> annual average of 1.2 faults per mile. Therefore, the target segments perform at least 50% worse than the overall OH average for DEC NC of 0.81 faults/mile. [58].

The scale and cost of the TUG program is very sensitive to the assumed ETM threshold. If, for example, the Company used an ETM threshold of 16 instead of 12, the TUG program would have 1,754 fewer miles (a 29% reduction from the current plan) and cost at least $789 million[59] less. If the Company used an ETM threshold of 24 instead of 12, the TUG program would have 3,552 fewer miles (a 60% reduction from the current plan) and cost at least $1.6 billion less. The Company should be required to demonstrate why its "policy" of targeting overhead segments where performance is 50% worse than average (an ETF threshold of 12) is prudent.

Q. WHAT CONCERNS DO YOU HAVE ABOUT THE TUG COST ESTIMATES?

A. The Company claims that "[t]he bulk of this [TUG] program focuses on fused tap lines that run through residential neighborhoods. For this work, total cost estimates are based on unit costs of $400K-$500K per mile to convert overhead to underground. Feeder level undergrounding, is much more costly, typically running well over $1 million per mile. These costs are based on industry benchmarking for tap line undergrounding."[60] Further, according to the Company, there are 1,631 planned TUG projects with the circuit segment length greater than 1 mile.

[58] Duke Energy Carolinas, LLC Response to NCSEA Data Request No.10-9 (attached as Exhibit CG-12).
[59] Assuming a cost of $450,000 per mile for undergrounding.
[60] Power Forward Carolinas Executive Technical Overview, p.9.

The average length of these projects is 1.8 miles, and 47% of the circuit segments identified in these projects are protected by reclosers or sectionalizers, not fuses. These projects are likely more complex than just "fused tap lines that run through residential neighborhoods" and likely more costly. Using the Company's estimate of $450 thousand per mile, the total cost for these 1,631 projects would be $1.3 billion. If these projects are similar to more complex "feeder level" undergrounding and cost $1 million per mile, the total cost of the 1,631 projects balloons to $2.9 billion.

I believe the Company significantly understated the potential cost of its TUG program and should be required to develop more realistic cost estimates that accurately reflect the complexity of each proposed project.

Q. WHAT OTHER CONCERNS DO YOU HAVE ABOUT THE PROGRAM?

A. The Company claims the need to replace equipment, such as transformers, because they are approaching the end of their design life. Specifically, Witness Simpson states that "Over the next ten years approximately 30 percent of the Company's grid infrastructure will be beyond asset life."[61]

Q. HOW HAS THE COMPANY DETERMINED THAT 30% OF ITS INFRASTRUCTURE WILL BE BEYOND ASSET LIFE IN THE NEXT TEN YEARS?

A. In response to a NCSEA data request, the Company provided an analysis showing the vintage range of various transmission and distribution FERC accounts based on

[61] Simpson Direct, p. 20

the original cost of the assets[62]. The analysis includes asset categories such as land & land rights, road and trails, poles, and towers in addition to conductor, transformers and other equipment. The sum of the original costs of assets in service prior to 1995 (30 years before 2025) is 33% of the Company's total. The analysis provides a plant accounting perspective of the age of the Company's T&D system, but doesn't reflect the age of individual system components.

Q. MUST EQUIPMENT BE REPLACED ONCE IT HAS REACH ITS DESIGN LIFE OF 30 YEARS?

A. No. T&D equipment frequently performs well beyond its designed life and decisions to replace equipment should be based on a broader set of risk assessment factors, not just age.

Q. CAN YOU PROVIDE EXAMPLES?

A. Yes. Properly maintained and treated wood poles have a predicted service life of more than 100 years in North Carolina[63]. For transformers, the Institute of Electrical and Electronics Engineers ("IEEE") standard C57.91-2011 – Guide for Loading Mineral Oil Immersed Transformers and Step-Voltage Regulators contains loading analysis equations to model transformer thermal behavior and insulation aging under various loading conditions. The nameplate kVA rating of a transformer represents the amount of loading that will result in the rated temperature when the unit is operated under normal service conditions. When operating under these conditions, a transformer has an expected useful life of 20 to 30 years.

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[62] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 2-14.
[63] http://www.osmose.com/content/pages/wood-pole-lifecycle-data.

The useful life of a transformer increases significantly when loaded below its nameplate rating and the operating temperature is below the maximum temperature rating. Most transformers never operate at maximum design conditions and run much cooler than the conditions for which they were designed. As a result, life expectancies increase, and most transformers last much longer than 20-30 years. Therefore, as I stated previously, decisions to replace equipment should be based on a broader set of risk assessment factors beyond just age.

Q. HAS THE COMPANY CONDUCTED SUCH A RISK ASSESSMENT?

A. In response to a NCSEA data request, the Company stated, "[t]he risk assessment approach used by the Company to identify the equipment to be replaced or retrofitted as part of the Distribution Hardening and Resiliency programs is driven by root causes of outages on our system, managing the system risk (safety, liability, environmental, etc.), customer satisfaction and component failure rate."[64]. The Company did not provide any detail of its methodology beyond this statement so we were unable to evaluate its approach. The Company should be required to provide a detailed and transparent explanation of its risk assessment and prioritization methodologies for both the Distribution Hardening and Resiliency and Transmission Improvements programs.

Q. DID THE COMPANY CONSIDER ANY ALTERNATIVES SUCH AS DER TO LOWER THE COST OF ITS POWER/FORWARD PROPOSAL?

[64] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 10-10.

A. No, the Company neglected to evaluate DER as an alternative to any element of the proposal[65] and this is a significant missed opportunity. For example, the Company stated "DSM options were not explored as Power/Forward initiative opportunities. The Company manages DSM programs through its existing DSM/EE planning processes, rather than through Power/Forward."[66] The fact that the Company has failed to integrate within its organizational structure does not excuse the Company's neglect in considering DSM as a valuable resource for providing capacity and reliability services.

Q. ARE THERE OTHER EXAMPLES OF HOW DER COULD BE DEPLOYED TO LOWER THE POTENTIAL COSTS OF POWER/FORWARD?

A. Yes. The Company proposes to spend $500 million to build 2,000 miles of new distribution lines and feeder ties[67] to provide backfeed capability and reduce long-duration outages for small- and medium sized communities across 30 counties.[68] Combinations of DER, deployed as microgrids, can provide a much more cost effective and environmentally friendly alternative to building thousands of miles of distribution lines.

Q. ARE THERE EXAMPLES OF UTILITIES DEPLOYING MICROGRIDS TO COST-EFFECTIVELY IMPROVE CUSTOMER RELIABILITY?

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[65] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 4-4 (attached as Exhibit CG-13).
[66] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 2-44 (attached as Exhibit CG-14).
[67] Power/Forward Carolinas Executive Technical Overview, p. 22.
[68] Simpson Direct, pp. 28-29.

A. Yes. San Diego Gas & Electric ("SDG&E") deployed a microgrid as a less expensive alternative to building a second transmission line to improve reliability for the 2,800 customers of Borrego Springs, CA. SDG&E's Chief Engineer has stated that the microgrid is three to four times cheaper than the transmission alternative[69]. Similarly, distribution utility Alectra Utilities recently deployed a cost-effective microgrid to improve resilience and reliability for a 10,000 customer community north of Toronto[70].

Q. DOES THE COMPANY HAVE EXPERIENCE DEPLOYING MICROGRIDS FOR IMPROVING RELIABILITY OR SERVING REMOTE LOADS?

A. Yes, on a small scale. The Company is piloting microgrids in Charlotte's McAlpine neighborhood to provide backup power to a fire station[71] and at Mount Holly to test the capabilities of solar plus storage with various "smart" technologies[72]. More recently, the Company implemented its solar plus storage Mount Sterling microgrid project that will allow it to restore 13 acres of parkland and eliminate four miles of distribution lines serving a communications tower.[73] The Company should apply insights from these projects to evaluate continued deployment of microgrids for

[69]https://www.greentechmedia.com/articles/read/distributech-roundup-microgrids-on-the-march#gs.vaxlsco.
[70]https://www.powerstream.ca/innovation/midas-microgrid-solution/penetanguishene-microgrid-project html.
[71] https://www.cleanegroup.org/ceg-projects/resilient-power-project/featured-installations/mcalpine-creek/
[72] http://www.charlotteobserver.com/news/local/article138966568.html.
[73] *See* NCUC Docket No. E-2, Sub 1127.

improving remote community reliability rather than build 2,000 miles of more costly and environmentally disruptive feeder ties.

Q. BASED ON YOUR ASSESSMENT OF THE POWER/FORWARD PROGRAM ELEMENTS, WHAT DO YOU RECOMMEND?

A. As I stated previously, I recommend that the Commission initiate a proceeding and stakeholder process for a closer examination of the Company's Power/Forward plan. At minimum, this examination must include:

1. A detailed benefit/cost analysis:
    a. Reflecting current interruption cost savings for DE Carolina's customers and all projected O&M savings;
    b. Excluding benefits from job creation and other economic activity; and
    c. Reflecting TUG costs that accurately reflect the complexity of the proposed projects.
2. A determination of the most appropriate methodology and timeline to begin calculating and publishing circuit hosting capacity.
3. A thorough justification of the prioritization approach for the TUG program and its prudency.
4. A thorough examination of the risk assessment approach used for the Hardening & Resiliency and Transmission Improvements programs.
5. Full consideration of DER solutions as alternatives to traditional T&D investment.

V: THE P/F PROPOSAL IN BROADER CONTEXT AND THE RATE DESIGN IMPLICATIONS OF P/F AND THE MINUMUM SYSTEM STUDY

Q. IS THE P/F PROPOSAL REFLECTIVE OF A BROADER STRATEGY BY DUKE ENERGY CORPORATION?

A. Yes. A review of the Duke's 2016 fourth quarter shareholder presentation show that over the next three years Duke Energy Corporation will be growing the value of the Corporation through investments in the transmission and distribution system as opposed to investments in generation from a capital expenditure perspective. By 2021, T&D investments will represent 55% of total growth capital, compared to generation which will only represent 29%. This is a significant change from the historical investment strategies implemented by the Corporation. Across the entire Duke Energy Corporation portfolio, by 2021, T&D investments will represent 57% of the electric utilities & infrastructure growth capital.[74] The Company further states that "23% in growth capital versus a year ago, is driven by Grid investment in the Carolinas and natural gas infrastructure." Of the projected 23% growth in capital for Duke Energy Carolinas and Duke Energy Progress, 78% is attributed to P/F. When one takes a look at how Duke plans to make money for its shareholders it is incontestable that the plan is through the P/F.[75]

Q. CAN YOU EXPAND ON WHAT YOU MEAN BY THE PHRASE "GROWING THE VALUE"?

[74] Duke Energy Corporation, Fourth Quarter 2016 Earnings Review and Business Update, pp. 44-45, https://www.duke-energy.com/_/media/pdfs/our-company/investors/news-and-events/2017/1qresults/4q2016slidesr2.pdf?la=en.
[75] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 9-2.

A. In an era of flat or declining electricity demand, Duke Energy Corporation is shifting from being a company that primarily invests in generation to a company that primarily invests in distribution and transmission infrastructure. More specifically, for Duke Energy Corporation, the ability to continually maintain or grow profit margins for shareholders is dependent on a continued expansion of the rate base. As a result, Duke Energy Corporation plans to expand its rate base through investments in the transmission and distribution system and not through investments in generation.

Q. WHY DOES A SHIFT IN THE CAPITAL EXPENDITURES OF THE COMPANY AND ITS PARENT DUKE ENERGY CORPORATION MATTER WHEN IT COMES TO RATE DESIGN AND REGULATION IN NORTH CAROLINA?

A. How the Company grows the rate base will impact rate design, if allowed. Utility capital expenditures have been historically classified and recouped through different rate recovery mechanisms and different rate structures. I will expand on the specifics later, but broadly speaking the Company’s traditional approach to cost recovery and rate design delineates between T&D investments and generation investments. Typically, generation investments are recouped through some a measure of individual usage while T&D investments are recouped through a combination of fixed and variable charges on the customer’s bill. Therefore, a change made in the business model or cost recovery of the Company (as sought here) to allow the Company to grow the value of its rate base through T&D investments opens the door to grow the proportion of its customers' fixed charges.

Q. WHY IS IT IMPORTANT TO PLACE THE POWER/FORWARD PROPOSAL IN THE LARGER CONTEXT OF NATIONAL STRATEGY AND SHIFT IN INVESTMENT STRATEGY OF THE COMPANY?

A. In this testimony, I have scrutinized the Power/Forward proposal for its merits and overwhelmingly find that the proposal put forth by the Company is unsubstantiated and not in the interest of the ratepayers. But, even *if* the Power/Forward proposal was a reflection of customer's willingness to pay, there is still a need for this Commission to recognize that the Power/Forward proposal is representative of a completely different investment model by the Company and that the current mechanisms that guide cost recovery for distribution investment may not align with the tenants of prudent rate design.

Q. HOW IS THE COMPANY PROPOSING TO REQUEST RATE RECOVERY FOR THE POWER/FORWARD PROGRAM?

A. The GRR will be split between a fixed, customer related charge and a variable, energy charge. The determination to divide the GRR into two separate riders was in part to reflect the current mechanism of allocating distribution and transmission costs in the Company's cost of service analysis and also to separately identify the customer-related portion of the revenue requirement by rate class.[76]

Table 3 details the proposed revenues and charges for the 2018 GRR:

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[76] Pirro Direct, p. 22.

Rate Class	Customer Revenue	Monthly Charge	Non-Customer Revenue	Energy Charge ($/kWh)	Total Revenue	Class % Revenue
Residential	$14,653,999	$0.72	$10,918,736	$0.000511	$25,572,735	71.7%
General Service - Small	$1,891,089	$0.65	$1,648,154	$0.000380	$3,539,243	9.9%
General Service - Large	$72,689	$0.67	$1,358,542	$0.000281	$1,431,231	4.0%
Lighting	$0	N/A	$182,342	$0.000252	$182,342	0.5%
Traffic Signal Service	$42,467	$0.59	$1,393	$0.000134	$43,860	0.1%
Industrial Service	$30,857	$0.73	$613,354	$0.000309	$644,211	1.8%
OPTV-Secondary	$138,238	$0.69	$2,707,802	$0.000201	$2,846,040	8.0%
OPTV-Primary	$2,108	$0.56	$1,333,341	$0.000137	$1,335,449	3.7%
OPTV-Transmission	$0	$0.00	$70,709	$0.000079	$70,709	0.2%
TOTAL	$16,831,447		$18,834,375		$35,665,822	100.0%

Table 3. Details of GRR for 2018

Q. DO YOU TAKE ISSUE WITH THE USE OF A RIDER?

A. Riders are used in large part to allow utilities to obfuscate the risk of large capital investments because of depreciation and financing costs. Under traditional ratemaking the construction and financing costs any capital investment would accrue on the Company's balance sheet as construction progresses and be subject to the utilities cost of capital. When the construction financing costs, and any associated depreciation costs, are on the balance sheet, the Company, and ultimately its shareholders, bear the risk of financing the project and must discern whether the investment is fiscally responsible. Once the capital project is completed and approved, the Company would then passes on the accrued balance into rates. The main argument against this approach for ratepayers is that they would see a large increase in rates once the capital project is complete. However, this approach also requires the utility to bear some risk in capital investments.

With the GRR, the financing costs and the risk are passed into rates on an annual basis. The ratepayers would see a gradual increase in rates as the project is under construction. In that way, the Company is asking the customer to give them an interest free loan to finance capital costs of the project, instead of relying on capital markets. Under the GRR, ratepayers are also required to absorb rate increases if there are project delays and/or project cost increases. For example, if there are cost overruns with undergrounding power lines, customers would be responsible for those overruns.

Additionally, my issue with the GRR broadly is that the Company is asking for the ratepayers, not the Company or shareholders, to bear all the financial risk of P/F without any return on that investment. The P/F proposal looks like an excellent plan to grow shareholder profits, and the GRR will solidify that there is no risk to shareholders. However, P/F, as currently proposed, does not appear to provide any material benefits to the average customer and threatens to raise their rates by 20-50%.

Q. DO YOU HAVE CONCERNS WITH HOW THE GRR WAS DELINEATED BETWEEN A FIXED AND VARIABLE RIDER?

A. Yes. As outlined by NCSEA witness Justin Barnes, the Company determined the fixed and variable components of the GRR based on the methodology employed in its Minimum System Method. However, with the GRR, the Company did not allocate the individual investments of the P/F by FERC account. I find this troubling considering that the Company has stated that the investments set forth within the P/F proposal will align with expected customary T&D spend, which must be allocated by FERC account. More importantly, a failure to allocate by FERC account obscures the nature of the investments, which investments are inappropriate to be counted towards the minimum system, and which investments should not be considered customer-related. As a result, the fixed portion of the GRR is not determined by the type of investment but rather corresponds to the overall percentage of the distribution system classified as customer-related, which for the residential class is 62.6%.[77]

Q. THE COMPANY'S EY ANALYSIS SHOWS THAT COMMERCIAL AND INDUSTRIAL CUSTOMERS WILL RECEIVE THE OVERWHELMING MAJORITY OF THE DIRECT CUSTOMER BENEFITS FROM P/F. DO THE COMMERCIAL AND INDUSTRIAL CUSTOMERS SHOULDER THE MAJORITY OF THE GRR?

A. No. If the capital expenditures of the P/F proposal follow the distributional break-down as presented in the direct testimony of DEC Witness Michael Pirro, then the residential customer class will provide an estimated 87% of the revenue

[77] Duke Energy Carolinas, LLC Response to Public Staff Data Request No. 87-28b, embedded file.

requirement for Customer-related charges and 60% of the revenue requirement for the Energy Charge. In contrast, the residential customer class stands to receive 3% of the total direct benefits quantified in the EY analysis.[78]

Q. YOU STATED THAT THERE ARE OTHER ASPECTS OF COST RECOVERY THAT ARE IMPORTANT TO APPRAISE IN CONCERT WITH THE P/F PROPOSAL AND PRUDENT RATE DESIGN. CAN YOU EXPAND?

A. Yes. As outlined in more detail in the Direct Testimony of Justin Barnes, the other aspects of cost recovery to consider include the Company's determination of what constitutes as customer and non-customer related costs set forth in the P/F proposal, the Company's approach to its Minimum System Study, and the cost recovery of distribution investments through the basic facilities charge, which is a fixed charge on customers' bills. These aspects are all problematic to me when considering prudent rate design.

Q. WHAT IS YOUR CONCERN REGARDING THE MINIMUM SYSTEM STUDY AND THE POWER/FORWARD PROPOSAL, IN TERMS OF RATE DESIGN?

A. I am concerned with the minimum system study methodology and the cost allocation of distribution investments. NCSEA's witness Justin Barnes goes into detail on the flaws with the minimum system study and how it is facilitating a stronger use of fixed charges by the Company. Additionally, as stated earlier, I am

[78] EY Analysis Exhibit, p. 20.

concerned about the discrepancy between how distribution system costs are allocated for cost recovery when made through the customary spend and when they are made through P/F. How the Company allocates distribution investments made under the P/F favors cost recovery through fixed charges, compared to distribution investments made through customary spend, meaning that using the GRR to recoup distribution costs could mean greater fixed charges.

Many of the P/F costs are defined as customer-related under the GRR Rider but they would not be under Company's own minimum system study, which is used to determine cost allocation for customary spend. As NCSEA's witness Justin Barnes recognizes, underground lines and conduit are not part the Company's minimum system, but because the Company's GRR Rider method indirectly classifies all distribution spend as 62.6% customer-related, that means that 62.2% of the costs of undergrounding powerlines are recouped by using the overall distribution plant average through a customer charge. I find this internal contradiction within the Company's own accounting worrisome and fear that it incentivizes the use of the GRR as a means to recoup more distribution costs through a fixed customer charge.

My second concern is how the Company plans to allocate cost recovery for distribution investments moving forward. According to discovery response NCSEA 11-10, the Company intends to classify undergrounding as "standard" moving forward, which would result in the undergrounding of powerlines being included in future minimum system studies and the related costs would be recouped through the fixed, basic facilities charge. Undergrounding power lines is simply not a legitimate cost constituting inclusion within a minimum system study, but rather much more significant investment. Undergrounding powerlines projects for an astronomical cost of over $5 billion of capital investments by the Company over the next ten years. I use this example to highlight what appears to be the Company proposing a two-step process towards greatly increasing the use of fixed charges and, given the Company's distribution investment projections, put upward pressure on rates through fixed charges.

I am also concerned that that the Company has created a mechanism to push the bulk of the P/F investments through base rates and has already created a justification within the Minimum System Study to do so. In fact the Company recognizes that even if the GRR is not approved, then P/F investments will be recouped through base rates.[79] Given how the minimum system study classifies costs, then that cost recovery could come in form of a fixed charge.

If taken in combination with the proposed GRR and the larger shift in the Company's investment strategy, it appears the Company is proposing to spend over $20 billion dollars in the next ten years in distribution assets and has allocated a way to ensure that the bulk of those assets will either be recouped through riders or through fixed charges.

Q. BASED ON YOUR REVIEW, WHAT ARE THE IMPLICATIONS FOR CUSTOMER CONTROL OVER THEIR ENERGY USE AND ENERGY

[79] Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 9-1.Duke Energy Carolinas, LLC Response to NCSEA Data Request No. 9-17.

EXPENDITURES OF THE P/F PROPOSAL AND THE PROPOSED CUSTOMER CONNECT CHARGE INCREASE ARE APPROVED IN THEIR CURRENT FORM?

A. Based on my review of the Minimum System Study and the GRR, the vast majority of these investments will be recouped through a fixed charge on the customer's bill - either through the Customer Connect charge or through the GRR. This means that the ratepayers will have increasingly less control over the energy expenditures, while the Company will have increasingly more control over maintaining a growing rate base, insuring growing shareholder profits.

Q. BASED ON YOUR REVIEW, WHAT ARE THE IMPLICATIONS FOR ENERGY EFFIECIENCY AND DISTRIBUTED ENERGY RESOURCES IF THE POWER/FORWARD PROPOSAL IS APPROVED?

A. If unchecked, a growing use of riders and growing fixed charge would drastically undercut the market for energy efficiency and distributed energy resources. There are several research papers that make this argument.[80][81][82][83][84][85]

Q. BASED ON YOUR REVIEW, WHAT ARE THE IMPLICATIONS FOR THE REGULATORY AUTHORITY OF THE COMMISSION AND THE PRUDENCY OF RATE DESIGN IF POWER/FORWARD IS APPROVED AS SET FORTH IN THE COMPANY'S CURRENT PROPOSAL?

A. The purpose of regulation, in the context regulated monopolies, is to enforce on utilities the pricing discipline that competition enforces on companies in competitive markets. Furthermore, the role of a regulator is to align the interests of customers against the financial health of utilities. If unchecked, the Company is proposing a future where the customer's direct benefit or willingness to pay for a good is irrelevant and the customer's ability to make decisions over their energy expenditures are diminished against the shareholder's need to maintain growing

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[80] Whited, M., Woolf, T., & Daniel, J. (2016). "Caught in a Fix: The Problem with Fixed Charges for Electricity", *Synapse Energy Economics for Consumers Union*.

[81] Jim Lazar, Regulatory Assistance Project, "Electric Utility Residential Customer Charges and Minimum Bills: Alternative Approaches for Recovering Basic Distribution Costs" (2013) (hereinafter "Lazar, Minimum Bills"), http://www raponline.org/document/download/id/7361.

[82] Jim Lazar et al., *Revenue Regulation and Decoupling: A Guide to Theory and Application 1, Regulatory Assistance Project* (2011).

[83] Faruqui, A., Sergici, S, and Palmer, J., "The Impact of Dynamic Pricing on Low Income Customers", Edison Institute, (2010). http://www.edisonfoundation.net/IEE/Documents/IEE_LowIncomeDynamicPricing_0910.pdf.

[84] Nancy Brockway, Rick Hornby, "The Impact of Dynamic Pricing on Low-Income Customers: An Analysis of the IEE Whitepaper, Synapse Energy", (2010). http://www.synapse-energy.com/sites/default/files/SynapseReport.2010-11.MD-OPC.IEE-Low-Income-Customer-Report.10-042.pdf.

[85] Trevor R. Roycroft, "Impact of Dynamic Pricing on Low Income Consumers: Evaluation of the IEE Low Income Whitepaper" (2010), available at http://www.roycroftconsulting.org/Roycroft_Dynamic_Pricing_Low_Income_11-29-10.pdf.

profits. While that may be in the interest of the Company, it is by no means a reflection of a competitive market, the interest of ratepayers, or prudent rate design.

VI: COMPARISON OF THE COMPANY'S APPROACH TO POWER/FORWARD COMPARED TO BEST PRACTICES OF GRID INVESTMENT

Q. PLEASE SUMMARIZE YOUR EVALUATION OF THE COMPANY'S APPROACH TO THE POWER/FORWARD PROPOSAL IN TERMS OF THE POLICY PROCESS. Please summarize your evaluation of the Company's approach to the Power/Forward plan, in terms of the policy process?

A. In Docket No. E-2, Sub 1142, I outlined how Duke Energy Progress's approach to grid investment is markedly different from the rest of the country. This critique also applies to DE Carolinas. From my assessment, the Company has failed to engage in any of the following best practices of grid investment:

- Clear and Measurable Goals
- Stakeholder Engagement
- Integrated Distribution Planning
- Cost/Benefit Analysis

Q. HOW DID YOU DETERMINE THAT THE ABOVE ARE THE BEST PRACTICES OF GRID INVESTMENT?

A. To determine the best practices of grid investment process, I reviewed over twenty proceedings occurring across the country and literature from leaders in the field, including the Electric Power Research Institute ("EPRI"), Smart Electric Power Alliance ("SEPA"), North American Electric Reliability Corporation ("NERC"), the North Carolina Clean Energy Technology Center ("NCCETC"), and the Department of Energy ("DOE").

Q. PLEASE COMPARE THE APPROACH TAKEN BY THE COMPANY, IN TERMS OF POLICY PROCESS, TO OTHER JURISDICTIONS THROUGHOUT THE COUNTRY.

A. As stated, I have reviewed several, if not all, of the current grid investment proceedings transpiring throughout the country. While not all jurisdictions are engaging in all the best practices outlined above, my review finds that nearly every other jurisdiction is following at least two of these 'best practice' procedural components. Additionally, I should note that many of the jurisdictions I have reviewed are in different stages of the process and may not have executed on all procedural components, but intend to. In contrast, the Company has yet to embark on any of these procedural components.

	Stakeholder Process	Cost/Benefit Analysis	Defined Goals and/or Metrics	Integrated Distribution Planning
AZ	x	x		
CA	x	x	x	x
CO	x			
DC	x		x	x
HI	x	x		x
ID	x			
IL	x			x
MA	x	x	x	x
MD	x			x
MN	x		x	x
NH	x	x	x	x
NY	x	x	x	x
OH	x		x	
PA	x			
RI	x			x

Table 4. Grid investment Process Components, Comparison by active States

Q. WHY IS IT IMPORTANT THAT THE COMPANY ENGAGE IN THE POLICY PROCESS THAT YOU OUTLINED IN YOUR TESTIMONY IN THE DEP RATE CASE?

A. It is clear from my review of the Company's P/F proposal, as well as the justifications and supporting analysis provided by the Company to substantiate the P/F proposal, that there is a need for much stronger oversight, review, and transparency. In my professional career, I have never seen such unfounded arguments for such massive capital investments as set forth in the DEC and DEP rate cases. Following the process steps outlined in my direct testimony in the DEP rate case will at minimum ensure that any future monies spend by the Company on the grid are useful, efficient, and in the long-term interest of ratepayers[86].

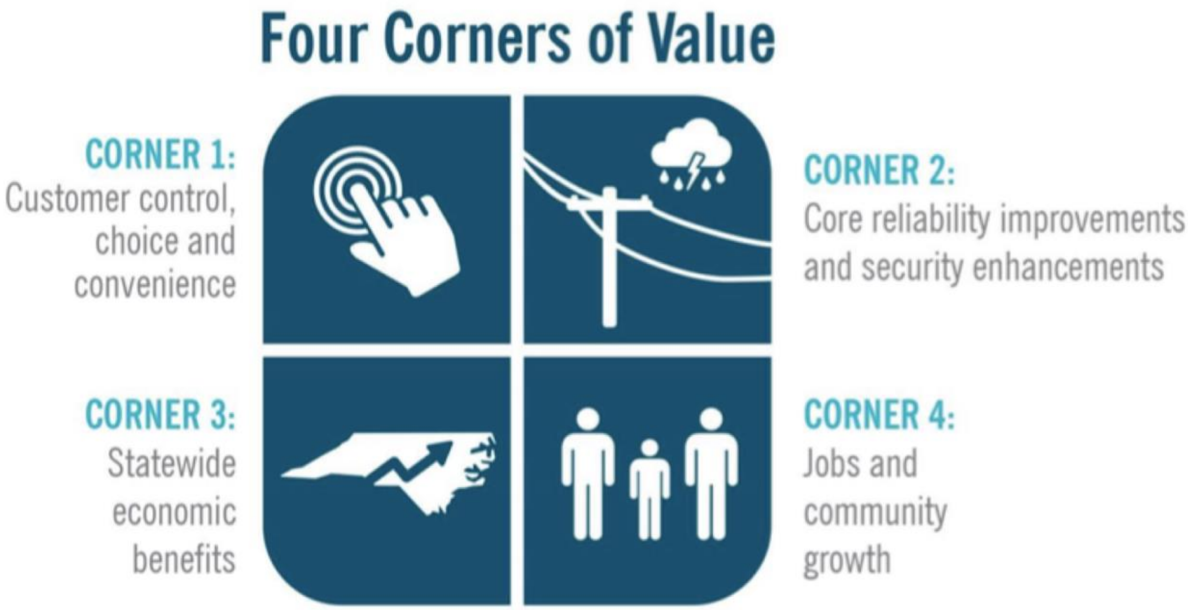
VII: CONCLUSIONS AND RECOMMENDATIONS

Q. BASED ON YOUR REVIEW, DOES THE P/F PROGRAM PROPOSED BY THE COMPANY ADHERE TO THE STANDARDS OF PRUDENT RATE DESIGN?

A. No, for several reasons. First, as demonstrated above, the costs associated with the P/F proposal do not justify the marginal benefits that will be experienced by ratepayers, establishing that the proposed investments are not prudent and reasonable. Second, the justification put forward by the Company is based on unsound, illogical, and irrelevant economic analysis. Third, the engineering and operational justification put forward by the Company is opaque and incoherent. Fourth, the proposed investment plan put forward by the Company is deeply flawed and unsubstantiated. Fifth, based on the above review, increasing investments in cost categories that utilize the use of riders and fixed charges for cost recovery diminishes customer control over their energy expenditures and violates the tenants of prudent rate design and cost causation. It's telling that the Duke Energy "Four

[86] *See* NCUC Docket No. E-2, 1142, Direct Testimony of Caroline Golin on Behalf of North Carolina Energy Association.

Corners of Value" [87] notably is missing any mention of just and reasonable rates and cost-justified investment of ratepayer dollars.



Q. GIVEN YOUR EVALUATION, DO YOU HAVE ANY RECOMMENDATIONS TO THE COMMISSION REGARDING THE COMPANY'S POWER/FORWARD PROPOSAL?

A. Yes. First, I recommend that the Commission deny cost recovery requested for Power/Forward through the GRR or through a regulatory asset deferent.

Second, I recommend that the Commission order the Company to open a stand-alone docket in order to thoroughly and thoughtful define and plan for a modernized grid. The stand-alone docket should be predicated on clear grid

[87] Power/Forward Carolinas Executive Technical Overview, p. 13.

investment goals and metrics. Duke should be required to conduct robust distribution resource planning that take a holistic view of the grid and the technologies that are capable of meeting grid needs. This includes the proper forecasting and evaluation of the role of DERs, the inclusion of third parties, and transparency in the analysis process. Distribution resource planning should be accompanied by thorough cost/benefit analyses that compare several investment pathways to meeting grid investment goals. Finally, Duke should be required to give greater deference to the role of DERs as potential investments for improved reliability.

Third, the Commission should open a docket or stakeholder working group, in tandem with the P/F proposal, to assess the impacts of shifts in the Company's investment strategy with the current mechanisms for cost recovery and implications for rate design.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**))))**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-1

Caroline Golin
caroline@votesolar.org
ww.votesolar.org

SUMMARY

Caroline Golin is the Southeast Regulatory Director for Vote Solar. Vote Solar is a non-profit organization working to foster economic opportunity and promote energy security by making solar a mainstream energy resource.

Caroline is a renewable energy policy expert with a focus on regulatory issues concerning distributed resources. Caroline's research has informed energy policy adoption and business practices at the local, state, and national levels, with recommendations adopted by several companies, cities and states. She has published and authored several studies related to the field of energy policy, renewable energy, the water-energy nexus, and the environmental impacts of energy and water use.

Areas of Expertise include:

- Distributed Energy Policy: Rate Design, Regulatory Challenges, Program Design, and Valuation
- Distributed Resource Planning
- Environmental Economics of Energy Generation

EDUCATION

Doctorate in Energy Policy. *Georgia Institute of Technology*, 2017.

Masters in Civil and Environmental Engineering (MSCE). *Georgia Institute of Technology*, 2014.

Bachelors of Arts (BA). *University of Florida*, 2007.

PAST ACTIVITIES

The Greenlink Group. Founder/CEO, September 2014 – April 2017

Principal Consultant and expert witness providing consulting services related to distributed resource policy and methods for quantifying policy impacts, with analytical experience in distributed solar policies.

Co-Creator of the ATHENIA Model, an integrated systems-environmental-economic modeling tool that can project hourly and daily social costs and benefits of energy and water policy shifts at the city, state, and utility scale.

Provide analysis and consultation related to utility filings, commission proceedings, and integrated resource planning on issues of rate design, policy, and generation investments in Virginia, Tennessee, North Carolina, South Carolina, Massachusetts, Rhode Island, Washington D.C, Ohio, and Georgia.

Provide analysis related to valuing distributed solar resources and community solar as well as consult on adoption in Tennessee, South Carolina, and Georgia.

Developed community solar program designs in Georgia and North Carolina, focusing on investor-owned utility models.

Provide expert testimony on the methods of valuing distributed resources, including the calculation of utility financials, rate impacts, avoided energy costs, avoided capacity costs, and the environmental externalities associated with traditional generation sources.

Provide consultation and analysis to cities on the most effective and economic measures for reducing energy and water use, including Atlanta, Orlando, Washington D.C, and Kansas City.

National Science Foundation IGERT Fellow. Georgia Institute of Technology**.** August 2011- December 2016

Propriety research conducted on energy and water management for Coca-Cola
Created models to assess impacts of shifts in energy and water use for the integration of distributed resources, specifically distributed solar.

Research on the adoption of sustainable water resource management systems for the integration of water and energy infrastructure development on the ACF River Basin

Energy Analyst. Georgia Department of Agriculture. Atlanta, GA

Worked with the Georgia Department of Agriculture to assess the potential for bioenergy use and solar powered irrigation systems in Georgia.

RELEVANT ANALYSES. PRESENTATIONS, AND PUBLICATIONS

- Prepared Direct Testimony on behalf of North Carolina Sustainable Energy Association in front of the North Carolina Utilities Commission, in Docket No. E-2 Sub 1142. October 2017
- Prepared Direct Testimony on behalf of Energy Freedom Coalition of America (Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Western Massachusetts Electric Company d/b/a Eversource Energy D.P.U. 10-70 March, 2017)
- Golin, Caroline and Xiaojing Sun. *The potential for Demand-Side Resource in the District of Columbia*. Prepared for the Department of Energy and Environment- January 2016.
- Prepared Direct Testimony on behalf of Georgia Interfaith Power and Light (Workshop to Examine Issues related to the Value of Renewable and Distributed Energy Resources in preparation for the 2016 Georgia Power Company Integrated Resource Plan Docket No. 39732)
- Prepared Direct Testimony on behalf of Energy Freedom Coalition of America (Investigation by the Department of Public Utilities on its own motion as to the propriety of the rates and charges proposed by Massachusetts Electric Company and Nantucket Electric Company in their petition for approval of an increase in base distribution rates for electric service pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00 et seq-March, 2016)
- Prepared Direct Testimony on behalf of The alliance for Solar Choice (Review of Electric Distribution Design Pursuant to R.I. Gen. Laws § 39-26.6-24**.** Docket No. 4568 – October 23, 2015)
- Prepared Direct Testimony on behalf of The alliance for Solar Choice (Review of Electric Distribution Design Pursuant to R.I. Gen. Laws § 39-26.6-24**.** Docket No. 4568 – November 23, 2015)
- Prepared Rebuttal Testimony on behalf of The alliance for Solar Choice (Review of Electric Distribution Design Pursuant to R.I. Gen. Laws § 39-26.6-24**.** Docket No. 4568 – January 6, 2015)
- Golin, Caroline and Southern Environmental Law Center. 2015. *A Troubling Trend in Rate Design: Proposed Rate Design Alternatives to Harmful Fixed Charges.* December, 2015

- Golin, C., Cox, M., Brown, M., & Thomas, V. 2015. The water efficiency gap. *Sustainable Water Resources Management*, 1-10.
- Golin, C. 2016. *Assessing the 'Cost Shift' for Residential PV under different rate designs.* Out for Review
- Matt Cox and Caroline Golin. 2015. *Analyzing Kansas City's Building Energy Benchmarking & Reporting Draft Proposed Ordinance*
- Matt Cox and Caroline Golin. 2015. *Analyzing Orlando's Building Energy Benchmarking & Reporting Draft Proposed Ordinance*
- Prepared Interrogatories with Southern Environmental Law Center on behalf of Appalachian Voices and the Chesapeake Climate Action Network (No PUE-2015-0006).
- Golin, Caroline and Matt Cox. 2015. *Determining the Value of Solar in Georgia*
- UNC Nexus 2015: Water, Food, Climate and Energy Conference. Paper presenter: Water in the Wires.
- Prepared Direct Testimony of Caroline Golin on behalf of the Southern Alliance for Clean Energy (Docket 2014-246-E-December 10, 2014)
- Matt Cox and Caroline Golin. 2014. *The Impacts of Net Metering in South Carolina.* Presented as supporting evidence for Direct Testimony in Docket 2014-246-E-December 10, 2014 on behalf of the Southern Environmental Law Center
- Golin, Caroline (2014). Common Pollutants Impact Methodology. Original methodology submitted to the Tennessee Valley Authority Distributed Generation-Integrated Value Stakeholder Group.
- Golin, Caroline (2014). Water Use Impact Methodology. Original methodology submitted to the Tennessee Valley Authority Distributed Generation-Integrated Value Stakeholder Group.
- Golin, Caroline. The Greenlink Group (2014), Additional Explanation of Methodologies Underlying Additional Environmental Considerations Section, submitted by the Southern Environmental Law Center.
- C3E with MIT & Clean Energy Ministerial. 2014. Award Winner. The ForeSEE Model.
- Golin, Caroline, et al. 2013.*Toward a comprehensive framework for nanomaterials: An interdisciplinary assessment of the current Environmental Health and Safety Regulation regarding the handling of carbon nanotubes*. J. Chem. Health Safety
- Georgia Environmental Conference. 2012. Research presented on the Health Impacts of Coal-fired Electricity Production.
- Solar Power International Conference. 2012. Research presented on the Health Impacts of Coal-fired Electricity Production and Benefits of Distributed Solar.
- Golin, Caroline. 2012. *Towards the Full Cost of Coal: A review of the recent literature assessing the negative health care externalities associated with coal-fired electricity production.* Filed before the Georgia Public Services Commission- September 20, 2012.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-2

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 56-15

Docket No. E-7, Sub 1146

Date of Request: **November 16, 2017**
Date of Response: **November 27, 2017**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 56-15, was provided to me by the following individual(s): Melissa B. Culbreth, Director, Distribution Operations Finance, Regulated Utilities Finance, and was provided to NC Public Staff under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

NCPS 56-15

Request:

Please provide all cost benefit analyses related to any projects proposed to be included in the proposed GRR Rider.

Response:

The Company developed the Power Forward Carolinas - Executive Technical Overview, which incorporated an EY economic impact analysis, to outline the costs and benefits for the Power/Forward programs as a whole.

See attached:

"PSDR 56-15 EY QUEST Duke Energy NC PowerForward Impact.pdf"

PSDR 56-15 EY
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"PSDR 56-15 Power Forward Carolinas - Executive Technical Overview.pdf"

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Power/Forward Carolinas

Executive Technical Overview

EXECUTIVE SUMMARY

North Carolinians expect and deserve reliable, clean, sustainable and affordable energy. And Duke Energy has a proven track record of supplying and delivering energy to millions of customers. In 2016, power reliability was 99.97 percent, rates remained nearly 20 percent below the national average and our coal plant fleet continued to shrink – down by half since 2005 reducing carbon dioxide emissions by 29 percent.

But the world is changing, and so, too, are customer expectations. Everything today is digitally- and technology-based, providing consumers with more information and control than ever before. These technological and customer-driven changes have imposed different demands on the electric power grid. Individuals and businesses are increasingly demanding perfect power and with the explosive growth in the state's population, the grid is being tasked like never before to operate reliably, all of which is accelerating the aging process.

Citizens across the state are just now experiencing the effects of a grid that needs to be modernized. Outage events are trending up, the duration of events is growing and major event damage continues, leading to longer outage times. Without additional investment, approximately 30 percent of our grid will exceed its 30-year design life over the next 10 years.

Duke Energy has developed a bold 10-year plan, Power/Forward Carolinas, that will make the grid more reliable, while also making it smarter and more secure. Third-party economic evaluations of the $13 billion grid improvement plan indicate that over the 10-year implementation period, in addition to providing significant reliability and customer service improvements, Power/Forward Carolinas will stimulate approximately $33 billion in economic growth for the state of North Carolina.

About this overview

The purpose of this report is to provide an overview of the Power/Forward Carolinas grid improvement plan and highlight the benefits and value to the Duke Energy customers of North Carolina.

Contents include:

November 2017

1.0 THE NEED IS CLEAR

North Carolina customers expect more control, options and convenience when it comes to their energy experience. We rely on perfect power for everything. From routine, day-to-day activities -- like charging a cell phone -- to powering large data storage centers and high-tech manufacturing, the electric power grid has become the backbone of our state's digital economy and the electrons that flow through it are its virtual lifeblood.

But despite investing approximately $1 billion annually in preventative maintenance, reliability is declining. The grid and its components are aging, not advancing; outage events – including major weather events -- are on the rise, and North Carolina is experiencing the impacts.

Customer expectations have changed

Customers -- more than ever -- expect more options, greater reliability and value. This change in expectations has been greatly influenced by the ongoing evolution and disruption of retail markets, both online and in physical outlets, resulting from increased e-commerce, or the "Amazon Effect." Self-selecting billing and payment dates, scheduling appointments, accessing real-time data, perfect power and immediate service repairs after outages are all examples of basic services consumers expect but require technology to deliver.

A 2017 J.D. Power and Associates satisfaction study of electric utility residential customers confirms this shift in expectations, finding, among other things that:

- More customers are now going directly to their utilities' website for information, with more than one third of customers accessing website content by mobile phones or tablets.
- Customers who experience extended outage are less satisfied when the outage is caused by equipment failure [Duke Energy's fault] vs. a hurricane or auto accident.
- Customers' satisfaction increases during outage events with each additional piece of information that is provided (e.g. outage start time, cause, number of customers affected, etc.)
- Customers are more satisfied with the price they pay when they hear about rate increases and infrastructure investment, reliability and power supply.

To deliver on customer expectations, we must do more than maintain the power grid; we must make the appropriate investments to transform it, leveraging technology to modernize its operation, making it more reliable, smart and secure.

People rely on electricity more than ever to power their lives and businesses. Power is no longer a convenience nor is it a luxury.

Increasingly, all electric power customers, whether residential, industrial or commercial, rely upon electricity every minute of every day. Similar to roads and bridges serving as vital arteries for our Tar Heel state, prosperous communities and our state economy are powered by reliable electricity. Reliable power is now an absolute necessity.

At Duke Energy, we currently invest $1B annually in preventative maintenance for our reliable grid. Year-after-year, we have replaced mechanical components with mechanical components. However, the new demands on the power grid from customer expectations using digital technology and an expectation for greater reliability cannot be met without implementing our bold 10-year Power/Forward plan.

Proven industry data including System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI) metrics are reflecting our power grid's experience with increased weather events and greater demands. Recent benchmarking against utility peers reveals that Duke Energy Progress and Duke Energy Carolinas are in or nearing fourth quartile performance for reliability.

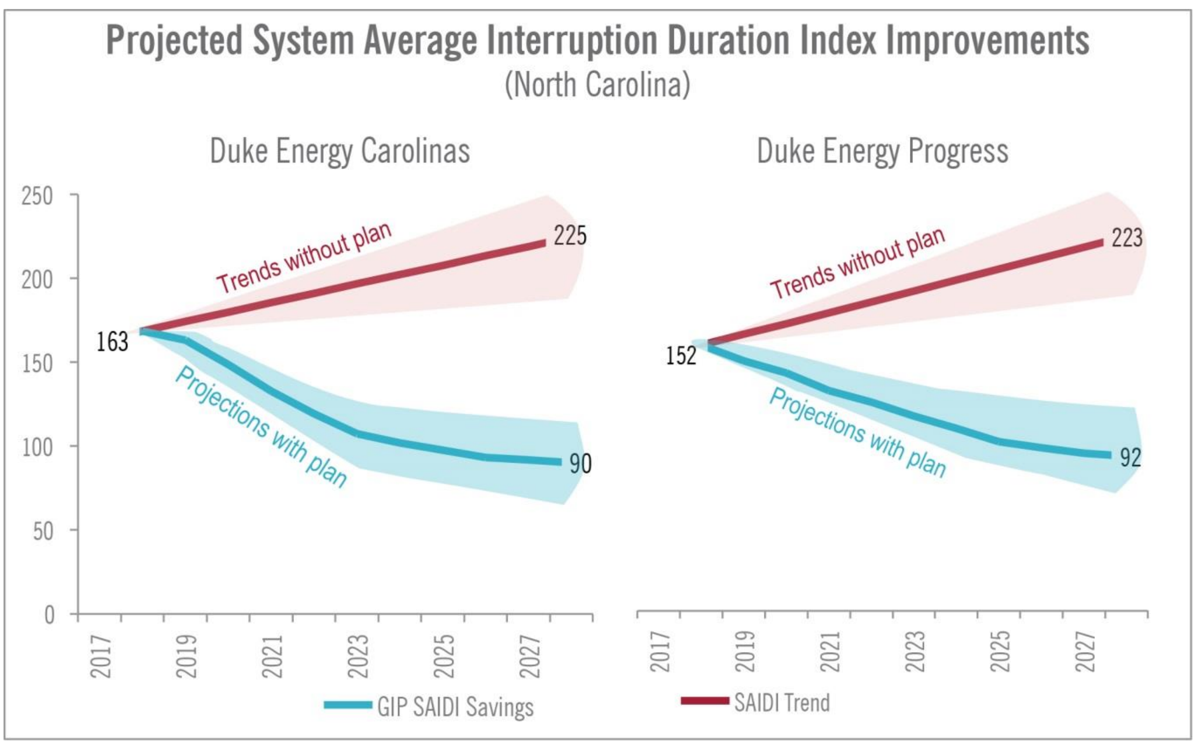


Figure 1 – 10 years of projected North Carolina SAIDI values starting with the 2017 year-end projection and ending at the 2028 year-end projection. The information charted denotes 10 years of SAIDI projections both with and without Power/Forward for DEC and DEP (NC only).

Power/Forward Carolinas will reduce the number and duration of routine outage events for customers. To determine the reliability improvements expected from Power/Forward programs, our engineers applied decades of historical data from tracking performance of power reliability programs and projected the impacts of the individual program measures found in Power/Forward. Those improvements were factored into the SAIDI and SAIFI forward-looking trend projections to produce the performance with the Power/Forward impacts (blue lines in figure 1.) To acknowledge the increasing uncertainty of these projections further out in time, we have overlaid cones of uncertainty for each reliability measure forecast. These cones of uncertainty are merely illustrative. Additional work is underway to apply even more rigorous methods to determine actual levels of forecast uncertainty.

Figure 1 clearly denotes a projected SAIDI improvement of up to 60%. The additional projections found in Appendix B illustrate similar findings for SAIFI.

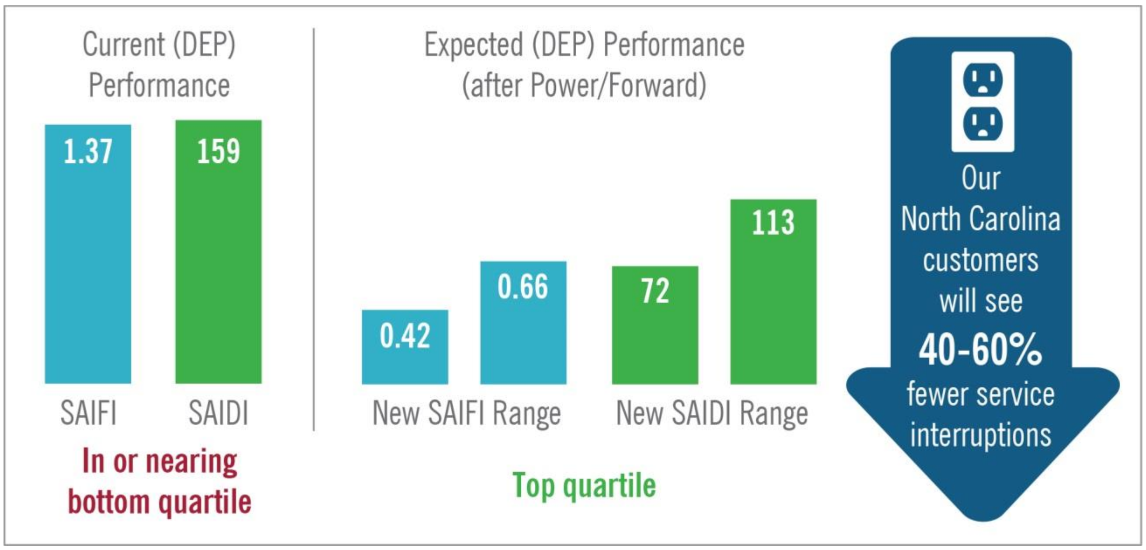


Figure 2 – This data reflects significant improvements that occur in Duke Energy Progress' SAIFI and SAIDI reliability performance measures in NC after Power/Forward is implemented. (Ranges of improved performance are based on historic load and weather information and do not reflect any impacts from changes in weather severity or customer

Similarly, Figure 2 provides a sample of the impact of Power/Forward on SAIDI and SAIFI for DEP in North Carolina. Beginning with 2016 year-end value of DEP SAIFI and SAIDI (1.37 and 159, respectively), upon full implementation of Power/Forward, Duke Energy expects to see SAIFI and SAIDI improvement in the range of 40-60%.

Interestingly, according to J.D. Power research, customers who experience a series of momentary power outages are just as unhappy as those with a sustained power outage.

To achieve fewer outages and greater reliability, businesses and households will necessarily experience an increase in rates as a result of these investments.

Here are a number of actual examples of reliability impacts across NC and our customer base:

1) According to a 2017 economic impact study performed by EY, at current grid performance levels, retail electric customers in North Carolina have approximately $1.17 billion in outage costs annually related to normal service interruptions (non-major events), with businesses making up 98% of this impact. These business losses could have represented potential costs savings and reinvestments in growth and new hiring by local North Carolina businesses.

2) An industrial customer reported actual lost profit margins of nearly $70,000 from four hours of outage time following Hurricane Irma.

3) A Materials Producer reported $3.5M loss due to a single plant interruption

Clearly, improvements from the Power/Forward Carolinas investment will result in fewer outages and blinks and provide much more reliable power for customers in North Carolina.

Severe weather events are increasing, and the threat of cyber and physical attacks on the grid are real.

Our grid is responding to an increasing number of storms. The National Weather Service has cited an 80% increase in the number of severe weather events impacting the U.S. from 2000 to 2016, which has led to an increase in major event days (MEDs). Wind and ice storms are two of the leading causes of outage conditions for our power systems, and flooding has also become an increasing concern.

Within North Carolina, we have seen the impact firsthand from such storms. Analysis of the past 10 years of North Carolina outage data shows that in an average year, nearly 1.2 million North Carolina homes and businesses are impacted. During Hurricane Matthew in 2016, North Carolina households and businesses experienced over 950 million minutes of power interruption, with some communities without power for more than six days.

A **major event day (MED)** is a day in which a major reliability event, such as a hurricane or major ice storm, causes an electric utility to shift into a "storm restoration mode" of operation in order to adequately respond. IEEE Standard 1366 statistically defines a major event day as any calendar day when SAIDI exceeds 2.5 standard deviations from the previous five year log-normal distribution of SAIDI days in a system or region.

Combined with this, the threat of cyber and physical attacks on the grid are real, and of increasing concern. According to a USA Today analysis of federal energy records, about once every four days, part of the nation's power grid is struck by a cyber or physical attack, one which could leave millions in the dark. As one of the largest investor-owned utilities in the U.S., Duke Energy is a prime target for cyber-crime. Our Power/Forward Carolinas investments are designed to mitigate the impact of major storm events, as well as to protect and defend against critical cybersecurity risks.

Technology is now available to enable a transition from a mechanical grid that is aging to a more modern, digitized grid.

Our investments in the grid help to promote North Carolina's drive for continued growth and development. However, to date, these investments have been heavily focused on replacing like-for-like assets and equipment; with an increasingly global economy and greater need for consistent, reliable power, now is the time for us to invest in newer, smart technologies to meet the needs of the future.

A large portion of North Carolina's energy grid is reaching the end of its useful life. Nearly half of many critical grid assets will have reached the end of design life within the next 10 years, including, for example, over 30% of overhead conductor in North Carolina's Duke Energy Progress (DEP) territory; for overhead transformers, this value is 57%. However, our planned strategic investments will enable us to transition to a modern, digitized grid. This includes taking advantage of increasingly sophisticated technology advancements, and replacing aging infrastructure with better and more improved grid devices and systems that will allow us to meet the needs of a global and highly digitized economy. For example, installing self-optimizing technologies will enable us to better isolate faults and much more quickly re-route power, thereby, significantly reducing the average number of customers impacted by an outage.

Other advanced enterprise system technologies allow us to remotely monitor grid heath and improve overall system operations and maintenance activities. With deployment of digital smart meters, we are able to offer our customers increased options and services, providing increased customer control of their energy usage.

Over the next 10 years, our investment in these areas and others will take advantage of new technologies to create a smarter, resilient and more secure electric power that delivers the services our customers expect and deserve.

2.0 SEVEN STRATEGIC PROGRAMS

The Power/Forward Carolinas plan is comprised of seven strategic programs. Deploying these improvement programs will enable us to better meet our customers' needs and expectations, including better managing their energy usage and reducing outage frequency and duration. It will also enable us to accelerate storm restoration, protect against physical and cyber security threat and better manage distributed energy resources (DER) and energy storage technologies.

Figure 3 – Power/Forward Carolinas seven strategic programs

Power/Forward Carolinas -- Strategic Programs, by level of investment

Targeted Underground (TUG)	Converting heavily-treed neighborhoods prone to power outages from overhead to underground construction to decrease outages, reduce momentary interruptions (blinks), improve major storm restoration time, and improve customer satisfaction.
Distribution Hardening & Resiliency	Upgrading equipment to lower system outage risk due to asset failure (hardening) and to minimize the impacts of events and improve ability to recover rapidly when events occur (resiliency). This program also addresses asset end-of-life opportunities, system design, and physical and cyber security.
Transmission Improvements	Deploying equipment upgrades, flood mitigation, physical and cyber security, and system intelligence to make a smarter, more reliable and secure transmission system.
Self-Optimizing Grid (SOG)	Applying modernization investments to build a more resilient distribution system better able to isolate problems and re-route power to minimize impacts to our customers and communities. To enable SOG functionality, circuits will have automated switches approximately every 400 customers, or 2 MW peak load, or 3 miles in circuit segment length.
Advanced Metering Infrastructure (AMI)	Deploying digital smart meters and associated communication devices to provide enhanced customer billing and payment options, detailed usage data, and energy-savings tools, as well as enhanced operational functions such as automated meter-reading, remote service connections and outage detection.
Communication Network Upgrades	Providing high-speed, high bandwidth, secure communications pathways (fiber optic and wireless) for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.
Advanced Enterprise Systems	Upgrading systems that manage grid devices, monitor equipment health, analyze data from monitoring sensors to improve system operations and maintenance activities, and enable grid self-optimizing technologies.

Estimated Program Costs and Operational Benefits

Duke Energy expects to invest $13 billion in North Carolina to implement the plan's seven strategic programs over a 10-year period. In general, our standard planning and prioritization processes will be used for Power/Forward Carolinas programs. For new transformational programs (e.g., Self-Optimizing Grid, Targeted Underground), we have developed new guidelines to provide additional guidance on the planning, prioritization and execution of these programs.

We will evaluate viable solutions, as the planning work continues annually throughout the Power/Forward Carolinas initiative, to choose the most cost-effective solution accomplishing the objectives of the program and providing the most value to customers.

Program-level cost drivers and methodologies for each of the seven strategic programs are described below with supplemental information provided in *Appendix A, Power/Forward Carolinas Cost Estimate Supplemental Information.*

The program details and cost estimates outlined below represent the initial 10-year cost estimates for Power/Forward Carolinas and are not necessarily the full population of detailed projects that will be a part of the plan. Some projects are further along in the planning lifecycle and have more detailed budgets, while others are higher-level estimates of future efforts. Each year, we will scope and budget the work for the following year, which may shift funding among programs and projects, shift projects earlier or later in the timeline, or add or remove projects as applicable based on resource availability and benefit achievement.

10 Year Power/Forward Initiative Capital Investments

Targeted Underground	$4.9 B
Distribution Hardening and Resiliency	$3.5 B
Transmission Improvements	$2.2 B
Self-Optimizing Grid	$1.2 B
Advanced Metering Infrastructure	$549 M
Communications Network Upgrades	$546 M
Advanced Enterprise Systems	$103 M
Total	**$13 B**

Table 1 – 10 year investment for North Carolina programs

Program Cost Estimate Details

Targeted Underground – ($4.9B) The bulk of this program focuses on fused tap lines that run through residential neighborhoods. For this work, total cost estimates are based on unit costs of $400K-$500K per mile to convert overhead to underground. Feeder level undergrounding, is much more costly, typically running well over $1 million per mile. These costs are based on industry benchmarking for tap line undergrounding, and the scope of approx. 10,200 miles for North Carolina. These costs include engineering and construction, along with brownfield development costs to engage and negotiate with all customers impacted. For example, the Company will employ dedicated land agents and engagement specialists to secure easements, and estimates the need to secure ~7,500 easements across the enterprise in 2018 alone.

Program	Unit	# Units	Cost/Unit	Total $M
Targeted Underground	Miles	10,220	$400-$500K	$4,893

Distribution Hardening & Resiliency – ($3.5B) This program is made up of a variety of work streams. Many programs are based on historical unit cost averages per mile or foot. Examples in this category include cable replacement (4,500 miles at approx. $150K per mile) and deteriorated conductor replacement (6,600 miles at approx. $100K per mile). Others are based on historical unit cost averages per unit upgraded. Examples in this category include transformer retrofit (351,000 at approx. $1,200 per unit) and pole replacement (24,500 poles at approx. $3,300 per pole). Several programs do not fit into either category and their costs are based on subject matter expertise. An example of this is the area of vulnerability[1] program (23 locations at approx. $5 million per area).

Transmission Improvements – ($2.2B – NC) This program is made up of a variety of transmission grid reliability programs. Equipment engineers and subject matter experts have identified specific assets that need to be replaced to ensure continued transmission resiliency and reliability. There are 35 reliability programs identified to replace various types of equipment on transmission lines and in substations. The majority of the programs are based on historical unit cost averages per unit replaced. Examples in this category include breaker replacements, substation transformer replacements, and line equipment replacements and hardening. These cost estimates are asset-based, however, work will be implemented on a substation or site basis. Other programs such as Condition-Based Monitoring (CBM), Phasor Measurement Units, Health and Risk Management (HRM) and physical/cyber security programs, are project-based and have standalone cost estimates.

[1] Area of Vulnerability is defined as "a portion or portions of the electric distribution system where the risk and/or probability of a system disturbance results in an impactful service disruption to the customer(s) and correspondingly high economic, societal, or reputational impact."

Self-Optimizing Grid – ($1.2B) Approximately 50% of the distribution circuits (~1,500) in North Carolina, serving approx. 80% of the customers, will be upgraded to Self-Optimizing Grid guidelines for switch automation, connectivity, and capacity. Average unit cost per circuit is estimated at $840K and is based on historical cost averages for similar types of work. However, the standard deviation from this average is large, with costs ranging from $200K to $2 million per circuit. Many circuits already have appropriate connectivity and capacity and will only require switch automation. Other circuits will require significant capacity upgrades and new circuit ties.

Program	# Circuits	Cost/Unit	Total $M
Self-Optimizing Grid	1,500	$840,000	$1,260

Advanced Metering Infrastructure – ($549M) These costs are based on the standalone cost estimates provided previously for AMI in the 2017 Smart Grid Technology Plan Update.

Communications Network Upgrades – ($546M) This program is made up of a variety of work streams and the costs identified are the approximate allocations for DEC North Carolina and DEP North Carolina. Some of the programs are project-based and have standalone enterprise cost estimates—for example, the Land Mobile Radio End-of-Life project (in the Mission Critical Voice Communications workstream) allocation is estimated at $55.2M in DEC and $47.6M in DEP and the Vehicle Area Network allocation is estimated at $8.0M in DEC and $4.9 in DEP. Other communications efforts have been estimated based on historical unit upgrade cost averages. For example the tower and shelter upgrades are estimated at $500K per tower and $150K per shelter, based on historical average costs. These cost estimates are refined as specific vendor costs become available. DEC and DEP plan to replace approximately 37 towers ($500K per tower) and 23 shelters ($150K per shelter) during the 10-year plan ($30M) with the remainder of the budget ($6.1M) allocated to power supply replacement where necessary.

Advanced Enterprise Systems – ($103M) These cost estimates are based on the standalone cost estimates for each enterprise systems program (e.g., Distribution Management System, Outage Management System, SCADA). Costs identified are the approximate allocations for DEC North Carolina and DEP North Carolina.

Additional Operational Benefits

Beyond the positive impacts our Power/Forward plan produces for the state, we have begun to identify additional value created from our plan in the form of cost savings for North Carolina operations. Based on the reduction in outage events resulting from our 10-year grid improvement plan, and using standard engineering calculations, we estimate approximately $42 million annually in additional benefits in the form of reliability-related operation and maintenance (O&M) savings opportunities.

These outage event reduction O&M savings include:

- vegetation management ($14.8M)
- outage restoration activities ($15.3M)
- major storm event restoration ($11.9M)

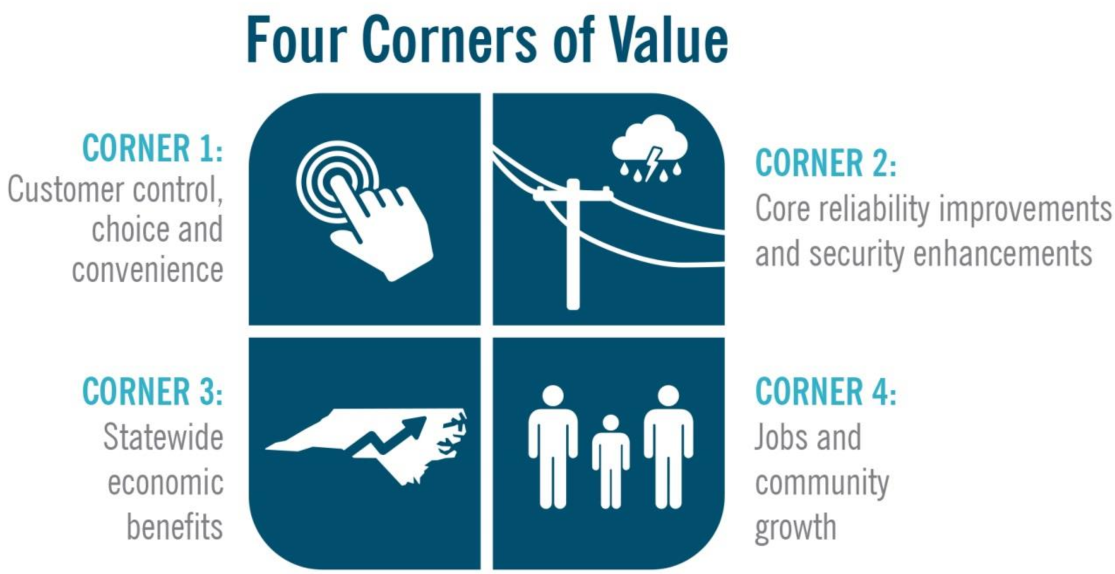
These values reflect O&M cost savings beginning in year 11 and do not include O&M cost savings resulting from our AMI program.

We anticipate additional Power/Forward plan benefits resulting from:

- Improved management of private distributed energy resources as customer adoption grows (e.g., grid-connected rooftop solar);
- Increased protection from cyber and physical security attacks;
- Improved environmental impacts from:
    - Reduced risk of oil spills and gas leaks due to applicable equipment replacements (estimated to avoid over 1300 gallons of oil spilled and 100 oil-spill events annually); this will also result in lower environmental clean-up costs (estimated to result in over $150,000 in annual savings across the Carolinas)
    - Reduced risk of avian collisions as a result of undergrounding overhead facilities (this will also result in cost reductions associated with levied fines relating to eagle and other bird impacts).

3.0 FOUR CORNERS OF VALUE

Duke Energy was born in the Carolinas, and we have proudly served our customers for more than 100 years. Our employees are deeply committed to the 3.2M households and businesses we serve. As guardians of the grid, we need to implement Power/Forward Carolinas, to move forward to provide even more options for customers through new products and services, improve core electric power reliability, drive economic growth, and develop jobs and communities. The benefits of Power/Forward Carolinas can be represented by examining the multiple ways in which value is advancing for customers and communities in North Carolina and the broader Carolinas region. We identify these areas of value, or "four corners," below.



Power/Forward Carolinas Value Proposition:

Below are several examples showing the value proposition Power/Forward will bring in each of the four corners.

Corner 1: Customer control, choice and convenience

- Access to new service and billing options like Pick Your Due Date and Usage Alerts.
- Ability for customer to see detailed usage data daily, making it easier to use energy more efficiently.
- Option to stop/start service remotely.
- Allowing for improved response times and speeds outage repairs.

Corner 2: Core reliability improvements and security enhancements[2]

- Reduction in regular-service outages by 40 – 60%
- Estimated 30% reduction in the frequency and duration of major event outages, including named storms and hurricanes
- Increased protection from cyber and physical security attacks

Table 2 shows the historic 10-year average numbers of customer interruption and minutes of interruption due to major events which are not reflected in SAIDI and SAIFI measures. Based on our analysis, the improvements implemented as part of Power/Forward would have reduced these impacts by one third.

REDUCTION IN MAJOR STORM IMPACTS	Customers interrupted (CI)	Customer Mins Interrupted (CMI)
10-year historical average, NC	1.2 million	815 million
Estimated reduction (%)	33%	30%
Power/Forward	**0.8 million**	**567 million**

Table 2 – Average annual MED events and duration anticipated in North Carolina (DEC and DEP) before and after Power Forward

Consider again the long and widespread outages stemming from Hurricane Matthew. This same analysis applied to Matthew shows a significant reduction in grid damage and associated restoration.

Table 3 illustrates that improvements implemented as part of Power/Forward would have eliminated more than 30% of the power outages experienced in Hurricane Matthew, reducing the total outage time North Carolina customers experienced (950 million minutes of interruption) by nearly 300 million minutes. This reduction allows customers to get back to work more quickly or better support their loved ones who were impacted. A fully implemented Power/Forward plan would have reduced our overall restoration from six days to four days (excluding area where flood waters prevented access).

Hurricane Matthew (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	30%	30%	34%
DEC NC	57%	45%	32%

Table 3 – Number and duration of Hurricane Matthew power outages in NC that would have been avoided with Power/Forward implementation

[2] Source: EY Study, *North Carolina impacts of Duke Energy's Power/Forward Grid Improvement Program*, November 2017

Corner 3: Statewide economic benefits

- Beyond the 10 year implementation of this plan, positive economic impacts will continue to be felt across the state. According to the third-party EY study, reliability improvements will result in an additional $12.9 billion in added economic activity for North Carolina.
- By 2028, the EY analysis shows that North Carolina businesses will save $1.7 billion per year from reduced outage-related costs.
- Generation of $1.1B in state and local taxes, with an additional $421M projected from reliability improvements

Corner 4: Jobs and community growth

- Approximately 12,000 jobs created for the state of North Carolina through the Duke Energy grid investment, plus an additional 7,000 for reliability improvements

Statewide Economic Benefits – additional details

As highlighted in our discussion of Power/Forward program costs, our grid improvement plan will mean direct capital investments of more than $13 billion over the 10-year plan. This level of direct capital investment will generate $20 billion in total economic output for the state of North Carolina throughout the investment period.

Duke Energy's capital investment will generate nearly $1.1 billion in state and local tax revenues. An estimated $518 million of this will be direct taxes paid by Duke Energy, including $330 million of state and local sales taxes on electrical equipment and installation materials.

Our capital investments will also support a total of approximately 12,000 jobs across the state, with Duke Energy employing an average of 6,200 direct employees and contractors.

Combined Value for North Carolina Customers and Communities

The combined value that Power/Forward generates for our North Carolina customers and statewide is $20 billion from the capital investment and an additional $12.9 billion from reliability improvements, resulting in a cumulative impact of approximately $33 billion.

Figure 7 below charts four dimensions of economic impacts (in millions of dollars) over the 10-year plan period.

1) **Customer Cost** (light gray line) – charts the contributions of North Carolina customers for the Power/Forward investments; this line is a function of electric rate increases over time.

2) **Baseline Customer Benefit** (dotted line) – charts the value of outage-related costs our customers avoid as a result of improved grid reliability; this value is a function of the decreasing number of power interruptions and outage times.

3) **Additional Customer Benefit Opportunity** (dark line) – charts the baseline customer benefits (illustrated by the dotted line) plus the additional potential value from converting those baseline savings into additional business profits; this is both a function of improving reliability and a function of how general market forces impact individual customers' businesses over time.

4) **Statewide Benefits** (blue line) – charts the total change in gross economic output for the state; this is a function of the reinvested business savings (illustrated by additional customer benefit opportunities, dark line) as well as the new jobs and the state's increased business activity created over time as a result of our direct Power/Forward capital investments.

Note that the overall statewide benefits continue to increase throughout the investment period peak investment year (2026). While the clearly measurable economic impacts from direct capital investments end with the cessation of our direct investing, the benefits resulting from the state's modernized and more reliable grid continue beyond 2028.

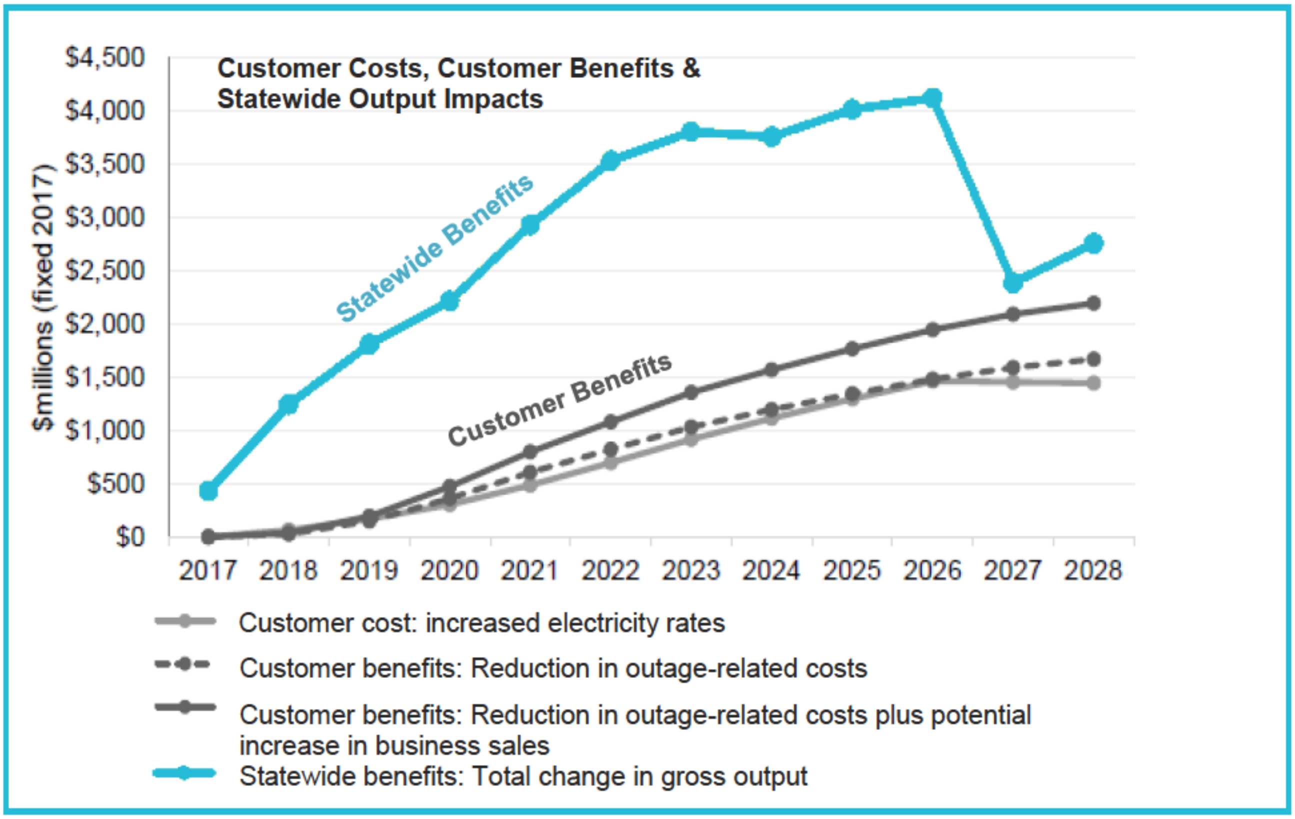


Figure 7 – Customer costs and benefits compared to statewide output impacts

The increase in costs borne by our customers associated with grid improvements (light gray line) are expected to continue until all capital investments are completed in 2026; after this point, costs will begin to fall with depreciation. The annual costs (incremental rate increases) will range from $62 million in 2018 to $1.4 billion by 2028. We anticipate reliability improvements to begin to generate avoided outage costs that could range from $29 million in 2018 to $1.7 billion by the end of 2028 (dotted line to dark gray line). If these avoided costs were then translated into new sales activity by businesses, reliability benefits could grow as high as $2.2 billion by 2028.

Thus, combining the maximum anticipated benefits from both the direct infrastructure investments and the improved reliability yields a total potential impact of approximately $33 billion for the state of North Carolina.

4.0 CONCLUSION

North Carolina needs an energy grid that is smarter, more reliable and secure to grow the economy, create jobs and enable the services consumers expect. And despite investing $1 billion annually into the state's energy grid, we need to implement Power/Forward Carolinas to advance and modernize the power grid infrastructure to position NC for future success.

Building on more than a century of service, Duke Energy's founding fathers envisioned a stronger North Carolina when they first harnessed the Catawba River for power generation leading to industrial growth across our great state. Today, we are in a similar position faced with the realities of an aging grid that in its current mechanical state will not sustain the growing expectations of our digitally-connected society.

To remain globally competitive, attract new business and serve the growing and changing expectations of our customers, North Carolina's grid must be modernized. The state's power grid is the backbone of our digital economy and the electricity flowing through its lines is the lifeblood that keeps the economy growing. We must act now and move forward together to build a stronger, more prosperous future.

This is our defining moment. Our bold plan – Power /Forward Carolinas -- positions NC and our customers for success now and for years to come.

Power/Forward Carolinas
SUPPLEMENTAL INFORMATION
(APPENDICES)

TABLE OF APPENDICES

APPENDIX A, POWER/FORWARD CAROLINAS COST ESTIMATE SUPPLEMENTAL INFORMATION

The information below is supplied as supplemental information for Power/Forward program costs for some of the programs identified in **Table A1**. The program details and cost estimates outlined below represent the initial 10-year cost estimates for Power/Forward Carolinas and are not necessarily the full population of detailed projects that will be a part of plan. Some projects are further along in the planning lifecycle to have more detailed budgets, while others are higher-level estimates of future efforts. Each year, the Company will scope and budget the work for future years, which may shift funding among programs and projects, shift projects earlier or later in the timeline, or add or remove projects as applicable based on resource availability and benefits achievement.

10-Year Power/Forward Initiative

Targeted Underground	$4.9 B
Distribution Hardening and Resiliency	$3.5 B
Transmission Improvements	$2.2 B
Self-Optimizing Grid	$1.2 B
Advanced Metering Infrastructure	$549 M
Communications Network Upgrades	$546 M
Advanced Enterprise Systems	$103 M
Total	**$13 B**

Table A1 – 10-year investment for North Carolina programs

Program level cost drivers and methodologies for each of the seven strategic programs are described in *Section 2.0 Power/Forward Program Costs*. The information below provides more granular budgeting details where appropriate.

Targeted Underground – ($4.9B) Using the budget methodology described for Targeted Underground in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

Program	Unit	# Units	Cost/Unit	Total $M
Targeted Underground	Miles	10,220	$400-$500K	$4,893

COUNTY	TUG MILES
Alexander	47.85
Anson	31.28
Avery	10.77
Beaufort	13.34
Bladen	33.75
Brunswick	51.17
Buncombe	618.88
Burke	104.85
Cabarrus	120.69
Caldwell	92.23
Carteret	73.93
Caswell	26.34
Catawba	207.41
Chatham	110.92
Cherokee	49.84
Cleveland	160.75
Columbus	94.34
Craven	45.64
Cumberland	97.92
Davidson	136.20
Davie	53.39
Duplin	75.56
Durham	198.82
Edgecombe	4.80
Forsyth	433.44
Franklin	54.73
Gaston	225.48

COUNTY	TUG MILES
Graham	46.58
Granville	43.79
Greene	4.76
Guilford	424.79
Halifax	6.98
Harnett	121.29
Haywood	182.93
Henderson	345.55
Hoke	29.43
Iredell	126.07
Jackson	177.18
Johnston	125.63
Jones	8.22
Lee	126.32
Lenoir	34.39
Lincoln	97.93
McDowell	121.60
Macon	166.97
Madison	8.00
Mecklenburg	752.42
Mitchell	47.90
Montgomery	71.78
Moore	176.96
Nash	63.47
New Hanover	317.25
Onslow	54.47
Orange	102.87

COUNTY	TUG MILES
Pamlico	17.50
Pender	61.20
Person	33.01
Pitt	10.20
Polk	92.66
Randolph	242.05
Richmond	98.13
Robeson	167.86
Rockingham	167.11
Rowan	321.35
Rutherford	155.82
Sampson	65.35
Scotland	48.76
Stanly	66.26
Stokes	66.13
Surry	135.27
Swain	116.83
Transylvania	84.01
Union	131.95
Vance	73.33
Wake	610.57
Warren	24.19
Wayne	118.23
Wi kes	129.59
Wilson	8.38
Yadkin	39.37
Yancey	5.69

Totals 10,220 miles in NC

Distribution Hardening & Resiliency — ($3.5B) Using the budget methodology described for Distribution Hardening & Resiliency in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

			DEC		DEP	
Program Description	**Unit**	**Cost/Unit**	**# Units**	**Total $M**	**# Units**	**Total $M**
Transformer Retrofit	Location	$1,152	7,000	$8.1	344,000	$396.3
Cable Replacement	Miles	$148,685	2,822	$419.6	1,681	$249.9
Sectionalization	Circuits	$20,000	1,008	$20.2	739	$14.8
Deteriorated Conductor Replacement / line rebuild	Miles	$100,000	3,145	$314.5	3,520	$352.0
Areas of Vulnerability	Locations	$5,000,000	15	$75.0	8	$40.0
Pole Hardening	Poles	$3,333	15,395	$51.3	9,171	$30.6
Capacity	Substations	$10,000,000	21	$210.0	6	$60.0
Live front switchgear and transformer replacement	# devices replaced	$25,000	1,248	$31.2	915	$22.9
Hazard Tree Removal		$1,000	14,400	$14.4	10,560	$10.6
Feeder Ties (for long duration outages)	Miles	$250,000	2,000	$500.0	750	$187.5
Oil-filled reclosers replacement	Reclosers	$50,000	528	$26.4	387	$19.4
Underground Riser Retrofit		$1,000	34,560	$34.6	25,344	$25.3
Electronic Recloser	Reclosers	$6,500	528	$3.4	387	$2.5
Hardening and resiliency programs requiring further engineering and scoping (e.g., structural guying, BIL uplift, physical and cyber security improvements, ampacity upgrades, etc.)				$231.2		$135.8
	10-Year NC Total		**DEC**	**$1,939.8**	**DEP**	**$1,547.5**
				Grand Total $ M	**$3,487.3**	

Transmission Improvements – ($2.75B – includes NC and SC) Using the budget methodology described for Transmission Improvements in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

	DEC			DEP		
Program Description	**# Units**	**Cost/ Unit**	**Total $M**	**# Units**	**Cost/Unit**	**Total $M**
Replace T-Oil Breakers w/Gas	400	$300,000	$120.0	200	$300,000	$60.0
Replace 230kV SF6 Breakers	50	$600,000	$30.0			
Replace 500kV Breakers	17	$895,000	$15.2	6	$895,000	$5.4
Replace D-Oil Breakers	500	$125,000	$62.5	400	$125,000	$50.0
Replace CCVTs 25+ or older	300	$22,000	$6.6	700	$22,000	$15.4
Replace RTU Replacement	50	$150,000	$7.5	84	$150,000	$12.6
Replace SBC Breaker Failure Relays	145	$150,000	$21.8			
Replace Electro-mechanical Relays per Terminal	500	$300,000	$150.0	400	$300,000	$120.0
Hybrid Relay Group scheme				116	$100,000	$11.6
Replace First Gen Relays	550	$180,000	$99.0	35	$180,000	$6.3
Install new Digital Fault Recorder (DFR)	3	$250,000	$0.8	10	$250,000	$2.5
Replace Digital Fault Recorder (DFR)	15	$250,000	$3.8	23	$250,000	$5.8
Replace Line Relay Carriers/Transfer Trip	15	$400,000	$6.0	27	$400,000	$10.8
Battery Bank Replacement				300	$15,000	$4.5
Replace Type U Bushings (count per transformer)	250	$100,000	$25.0	79	$102,000	$8.1
Bushings (count per transformer)				100	$102,000	$10.2
Replace Transformers - 1 PH & 3 PH	100	$2,000,000	$200.0	100	$2,000,000	$200.0
Replace Trench Reactors				46	$119,000	$5.5
Upgrade Load Tap Changer (LTC)	15	$300,000	$4.5			
Replace Silica Carbide Arresters	2500	$24,000	$60.0	250	$22,000	$5.5
Replace Voltage Regulators - 1PH	15	$70,606	$1.1			
Replace Voltage Regulators - 3PH	10	$240,000	$2.4	71	$350,000	$24.9
Replace Cap & Pin Insulators Bus Supports & Standoffs	4000	$25,000	$100.0			
Upgrade Transformer Coolers	21	$300,000	$6.3			
Emergent Equipment Replacements	10	$20,000,000	$200.0	8	$20,000,000	$160.0
Replace Substation Circuit Switchers				70	$150,000	$10.5
Replace OB Arresters				44	$22,000	$1.0
Wood Substations, Rebuild (incremental cost of wood)				48	$1,500,000	$72.0

	DEC			DEP		
Program Description	**# Units**	**Cost/ Unit**	**Total $M**	**# Units**	**Cost/Unit**	**Total $M**
Wood Pole Replacement	5000	$25,000	$125.0	7000	$25,000	$175.0
T-Line Rebuilds (Per Mile)	150	$1,500,000	$225.0			
Substation Animal Mitigation	80	$250,000	$20,000,000	60	$250,000	$15,000,000
Remote Sectionalizing Switches	75	$500,000	$37,500,000	100	$500,000	$50,000,000
T-Line Static Replacements (Per Mile)	250	$150,000	$37.5	300	$150,000	$45.0
T-Line Str/Tower Replacements	100	$189,000	$18.9	420	$189,000	$79.4
Replace T-Line Switches	100	$250,000	$25.0	132	$250,000	$33.0
Replace Cap & Pin Insulators Switches	400	$25,000	$10.0	130	$250,000	$32.5
Replace Polymer Insulators with Porcelain (Per Mile)	56	$200,000	$11.2	200	$300,000	$60.0
Physical & Cyber Security Improvements			$185,000,000			$102,000,000
System Intelligence HRM & CBM			$30,550,000			$16,450,000
		DEC Total:	**$1,575**		**DEP Total:**	**$1,167.3**
			Grand Total $ M:	**$2,742.2**		

Self-Optimizing Grid – ($1.2B) Using the budget methodology described for Self-Optimizing Grid in Section 2.0 Power/Forward Program Costs, the following budget has been developed. On average, three to four automated switches will be used for each circuit upgraded to SOG guidelines.

Program	**# Circuits**	**Cost/Unit**	**Total $M**
Self-Optimizing Grid	1,500	$840,000	$1,260

			DEC		DEP	
Program Description	**Unit**	**Cost/Unit**	**# Units**	**Total $M**	**# Units**	**Total $M**
Automation	Automated Switches	$50,000	3,550	$177.5	2,100	$105.0
Capacity & Connectivity	Circuit	$650,000	960	$624.0	540	$351.0
	10-Year NC Total		**DEC**	**$801.5**	**DEP**	**$456.0**
		Grand Total $M			**$1,257.5**	

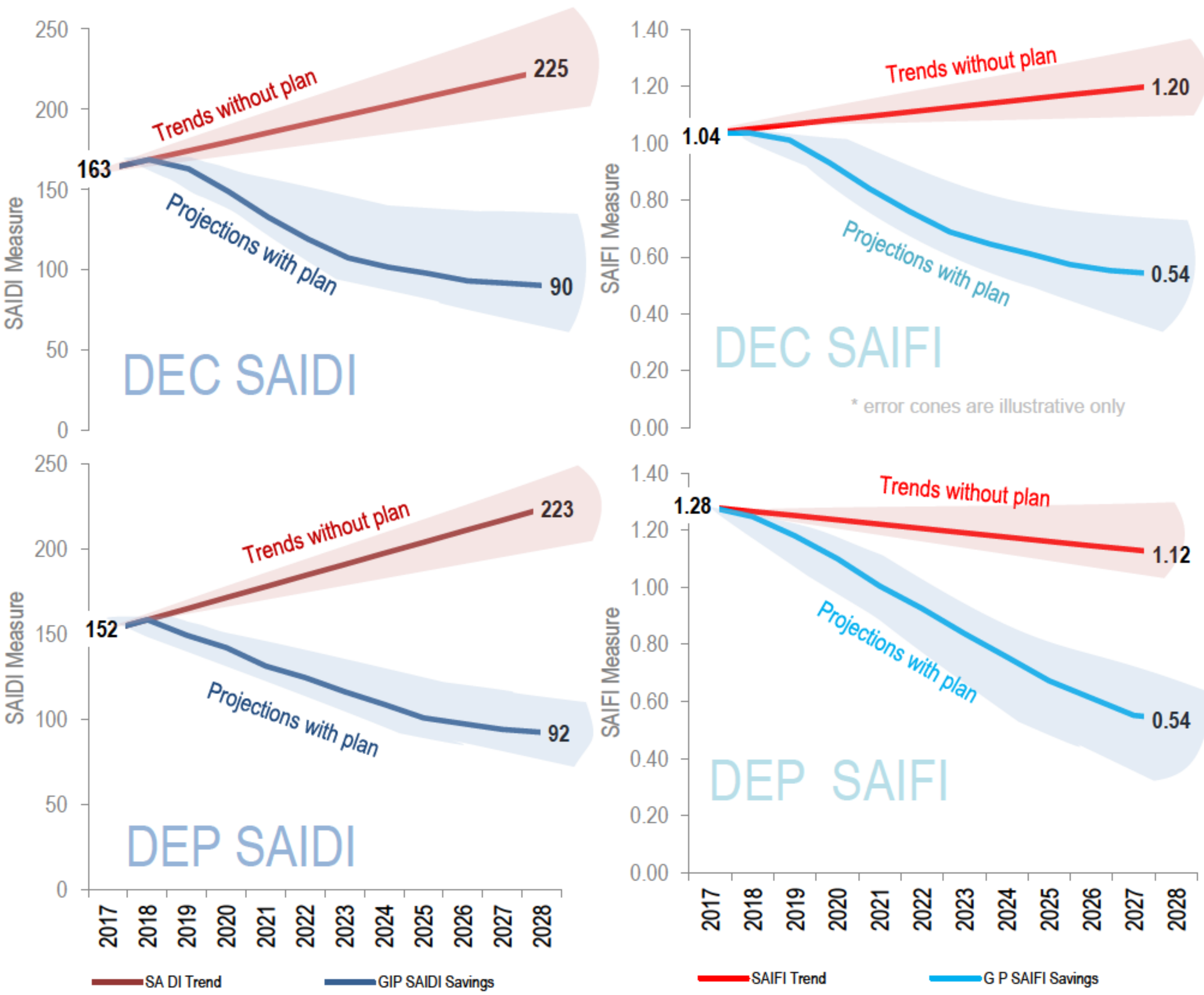
Communications Network Upgrades – – ($546M) Using the budget methodology described for Communications Network Upgrade in Section 2.0 Power/Forward Program Costs, the following budget has been developed.

Project Name	Totals $M*
Mission Critical Transport Network	258.5
Next Gen Cellular	30.9
Vehicle Area Network	10.7
Asset/Network & GIS Management	17.1
Mission Critical Voice Communications	100.8
Towers, Shelters & Power Supplies	36.3
BizWAN	3.9
GridWAN	38.3
Totals	**496.4***

* Reflects updated budget amounts

APPENDIX B, ADDITIONAL NORTH CAROLINA RELIABILITY MEASURES INFORMATION

Figures below represent the 10-year reliability measure projections for SAIDI and SAIFI for Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) in North Carolina with and without Power/Forward implementation.



About the Reliability Measures Projections

The 10-year "trends without plan" projections were developed from five years of historical non-MED outage data to ensure a sample size capable of producing an 80% confidence level. The mean value (μ) of each of the data set (DEC and DEP) was calculated and projected using linear regression techniques.

To acknowledge the increasing uncertainty of these projections the further out in time they are projected, we have overlaid cones of uncertainty for each reliability measure forecast. These cones of uncertainty are merely illustrative as we are working to apply rigorous methods to determine actual levels of forecasts uncertainty.

The 2017 starting value is a projection from the 2016 year end SAIDI and SAIFI measures for DEC and DEP.

APPENDIX C, PROJECTED IMPACTS AVOIDED DURING MAJOR STORMS

The tables below denote the forecasted customer impacts from named storms and major weather events (events that caused multi-day outages) that could have been from the past three years with Power/Forward Implementation. Customer Interruptions (CI) eliminated, Customer Minutes of Interruption (CMI) Eliminated and Outages Eliminated are shown in percentage reduction of actual event totals.

February 2014 Ice Storm

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	38%	42%	43%
DEC NC	46%	53%	38%

March 2014 Ice Storm

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	31%	33%	33%
DEC NC	41%	39%	27%

Winter Storm Remus (2015)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	23%	23%	31%
DEC NC	46%	44%	32%

Winter Storm Octavia (2015)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	25%	23%	37%
DEC NC	45%	43%	33%

Hurricane Hermine (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	27%	25%	42%
DEC NC	NA	NA	NA

Hurricane Irma (2016)

North Carolina	% CI Eliminated	% CMI Eliminated	% Outages Eliminated
DEP NC	33%	43%	44%
DEC NC	46%	39%	26%

APPENDIX D, MEASURING THE ECONOMIC IMPACT OF RELIABILITY IMPROVEMENTS

Measuring Costs Savings Associated with Core Reliability Improvements

To estimate businesses and households cost savings associated with core reliability improvements, EY used our SAIFI and SAIDI projections for non-major events along with our North Carolina customer segment data (i.e., numbers of residential, business, and commercial customers as inputs) into the Interruption Cost Estimate Calculator (ICE) developed by the U.S. Department of Energy and Lawrence Berkeley National Laboratory.

The ICE model specifically calculates the average interruption cost for residential, business, and commercial customers for a given SAIFI/SAIDI data pair using a regression model that takes into account factors such as the duration of the outage, the industry affected, household demographics patterns, and various seasonal factors. By estimating the difference in interruption costs associated with current SAIFI/SAIDI projections with and without implementation of the Power/Forward improvements, the annual direct cost savings resulting from our proposed grid improvements can be determined.

Measuring Costs Savings Associated with Reduced Major Storm Impact

To estimate businesses and households cost savings associated with *reduced major storm impacts*, EY used the annual averages for customer interruptions (CI) and customer minutes interrupted (CMI) associated with Major Event Days (MEDs). From this, EY projected estimates of the avoided CI and CMI anticipated from our Power/Forward improvements. Again, the data was input into the DOE/LBNL ICE tool to estimate the direct cost savings as our improved infrastructure comes on line over the 10 year investment period.

Measuring Additional Statewide Economic Impacts

Note that these direct cost savings do not capture the full economic impact of our reliability improvements. When North Carolina businesses experience these cost reductions, over time they will begin to expand their economic activities through additional purchases of raw inputs and the hiring of additional employees (*state wide benefits*). To estimate this <u>additional economic activity</u>, the IMPLAN model was used.

Both the reinvested business loss savings and the indirect and induced economic stimulus represent new economic activity that is the result of grid reliability improvements.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-3

Duke Energy Carolinas
Response to
Tech Customers
Data Request No. Tech Customers 2-11

Docket No. E-7, Sub 1146

Date of Request:	**November 27, 2017**
Date of Response:	**December 7, 2017**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to Tech Customers Data Request No. 2-11, was provided to me by the following individual(s): Melissa B. Culbreth, Director, Distribution Operations Finance, Regulated Utilities Finance, and was provided to Tech Customers under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

Tech Customers 2-11

Request:

With reference to the pre-filed direct testimony of DEC witness Simpson, page 23, how much were DEC's "customary capital expenditures on T&D," as that phrase is used on lines 6 and 7, for each of the years 2007 through 2016 (calculated the same way that the $4.5 billion provided on line 10 for 2017 through 2-21 was calculated).

Response:

The data pulled for the testimony was based on Assets placed in service by FERC. We don't have the 10-year period 2007-2016 but we do have a file for 2008-2017YTD. This file is attached in "2-11 Plant FERC Account.xlsx".

2-11 P ant FERC
Account.x sx

Duke Energy Carolinas, LLC

Note: The below 2008-2016 additions are from the annual FERC Form 1 pg. 204-207 - Electric Pl

		2008	2009
350	Land & Land Rights	6,132,172	1,331,790
352	Structures & Improvements	3,164,183	588,881
353	Station Equipment	39,168,770	34,527,065
354	Towers & Fixtures	3,259,944	20,908,463
355	Poles & Fixtures	44,381,859	11,622,226
356	Overhead Conductors & Devices	16,898,111	28,139,150
357	Underground Conduit	-	-
358	Undergr Conductors & Devices	-	2,929,953
359	Roads and Trails	-	-
	Total Transmission	113,005,039	100,047,528
360	Land & Land Rights	8,702,796	5,005,487
361	Structures and Improvements	9,954,564	9,373,051
362	Station Equipment	61,604,941	236,135,001
364	Poles, Towers, and Fixtures	15,806,169	39,828,845
365	Overhead Conductors & Devices	79,751,471	76,996,176
366	Underground Conduit	-2,122,311	1,681,411
367	Undergrd. Conductors & Devices	156,584,412	66,723,976
368	Line Transformers	50,292,054	(130,748,069)
369	Services	-20,415,113	17,210,104
370	Meters	20,512,508	17,280,646
371	Cust Premises/Load Cntrl Devices	59,813,674	41,156,921
373	St. Lighting & Signal System	13,279,668	13,373,629
	Total Distribution	453,764,833	394,017,178

ant in Service

2010	2011	2012	2013	2014
		Transmission		
4,369,868	7,829,528	1,053,717	11,066,251	819,659
5,264,566	3,460,089	860,179	5,564,661	(751,023)
56,496,643	87,699,646	63,849,458	93,227,301	50,956,041
24,748,711	(4,415,050)	16,208,007	83,994,277	40,352,816
31,138,755	17,357,489	20,778,301	24,940,381	16,737,490
22,766,165	29,920,327	40,155,305	24,061,629	29,843,587
-	5,345	-	-	-
(753,036)	5,237	-	586,420	1,248
-	-	-	-	-
144,031,672	141,862,611	142,904,967	243,440,920	137,959,818
		Distribution		
781,510	4,166,948	3,486,030	(1,625,388)	(2,550,508)
2,189,632	3,620,884	(6,513,792)	11,612,697	14,838,355
59,061,962	83,979,072	84,524,890	51,035,631	8,190,865
28,763,844	27,349,884	62,676,691	53,490,282	56,568,051
60,499,591	32,056,891	51,883,697	58,183,507	146,336,369
7,618,679	27,868,363	11,875,627	10,811,086	(27,803,741)
43,482,011	21,460,995	38,789,941	44,728,513	46,550,802
30,398,892	19,782,517	43,738,339	44,030,527	56,746,162
36,928,240	36,735,570	70,507,386	68,402,109	(5,838,437)
28,316,438	16,141,381	149,696	33,823,767	42,524,844
27,985,433	17,882,279	9,257,921	8,544,227	72,869,352
11,672,450	18,369,633	6,878,059	6,700,921	6,553,974
337,698,682	309,414,417	377,254,485	389,737,879	414,986,088

2015	2016	Jan-Jun 2017	Jul-Oct 2017	calc Jan-Oct 2017
700,513	9,275,828	3,106,116	1,884,028	4,990,144
13,911,285	8,960,465	27,868,773	(9,307,544)	18,561,229
85,561,010	78,690,980	95,372,516	112,052,767	207,425,283
29,416,714	(16,643,554)	(18,163,197)	(21,126,401)	(39,289,598)
27,472,466	30,096,127	46,990,428	46,838,461	93,828,889
44,389,702	78,682,602	2,040,998	(14,237,678)	(12,196,680)
-	13,569	87	220	307
-	65,077	(14,527)	1,391,159	1,376,632
-	-		-	-
201,451,690	189,141,094	157,201,194	117,495,012	274,696,206
1,930,233	(252,457)	585,912	1,423	587,335
11,245,547	15,075,484	3,550,436	5,106,256	8,656,692
69,089,230	69,309,436	41,924,030	12,602,723	54,526,753
59,632,485	83,978,786	(19,722,889)	37,860,803	18,137,914
148,542,569	100,916,715	66,676,827	37,584,035	104,260,862
(3,013,481)	6,692,614	5,423,883	1,378,019	6,801,902
46,432,938	77,847,850	34,988,023	38,715,546	73,703,569
40,235,077	54,032,307	23,167,563	21,690,879	44,858,442
11,707,346	42,685,100	19,587,049	15,038,321	34,625,370
25,175,214	70,608,335	82,348,874	48,721,585	131,070,459
44,799,605	25,201,701	94,314,228	20,293,696	114,607,924
11,689,670	8,390,590	10,675,116	3,759,935	14,435,051
467,466,433	554,486,461	363,519,052	242,753,221	606,272,273

11/20/17

11/20/17

Testimony

771,993,522 ties to testimony

1,826,676,861 ties to testimony

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-4

Duke Energy Carolinas Response to
Fourth Data Request of NCSEA
Data Request No. 4-5

Docket No. E-7, Sub 1146

Date of Request: **December 20, 2017**
Date of Response: **January 3, 2018**

☐ **CONFIDENTIAL**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 4-5, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

NCSEA 4-5

Request:

On page 14, lines 7-8 of Mr. Simpson's rebuttal testimony for Duke Energy Progress, LLC in Docket No. E-2, Sub 1142, he states: "Duke Energy began a formalized Integrated System & Operations Planning process in 2015."

As a subsidiary of Duke Energy, does DEC participate in Duke Energy's Integrated System & Operations Planning process? If so, please provide all data, analysis, studies, and reports related to this planning process. These documents should include, but are not limited to, minutes, presentations, and reports to Senior Management, to the Board of Directors, and to Board Committee. Please provide this data in Excel format with all formulas and links intact, where appropriate.

Response:

Please see attachment DEC NC - NCSEA 4-5.docx.

DEC NC - NCSEA
4-5.docx

DUKE ENERGY CAROLINAS, LLC

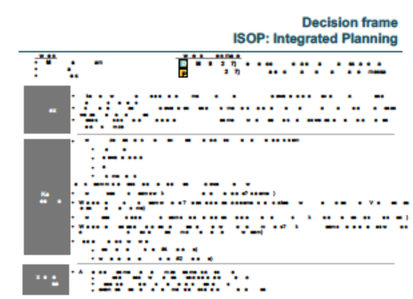
Request:

On page 14, lines 7-8 of Mr. Simpson's rebuttal testimony for Duke Energy Progress, LLC in Docket No. E-2, Sub 1142, he states: "Duke Energy began a formalized Integrated System & Operations Planning process in 2015."

As a subsidiary of Duke Energy, does DEC participate in Duke Energy's Integrated System & Operations Planning process? If so, please provide all data, analysis, studies, and reports related to this planning process. These documents should include, but are not limited to, minutes, presentations, and reports to Senior Management, to the Board of Directors, and to Board Committee. Please provide this data in Excel format with all formulas and links intact, where appropriate.

Response:

Please find attached the scope of the Integrated System & Operations Planning (ISOP) initiative as well as the presentation made to SMC in mid 2016 outlining the process and tools that were to be developed over time. The initiative is still on-going and many tools are either being tested or developed to fill the gaps identified (presented in SMC update deck). None of these tools are in-use



BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-5

Duke Energy Carolinas
Response to
Tech Customers
Data Request No. Tech Customers 2-9

Docket No. E-7, Sub 1146

Date of Request:	**November 27, 2017**
Date of Response:	**December 7, 2017**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to Tech Customers Data Request No. 2-9, was provided to me by the following individual(s): Justin C. Brown, Director, GS Planning & Regulatory Support, Grid Strategy & Investment Planning, and was provided to Tech Customers under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

Tech Customers 2-9

Request:

Please describe the approach employed by DEC to differentiate between an investment included in the traditional T&D category (i.e., within the forecast $4.5 billion budget) and an investment included in Power/Forward Carolina (i.e., within the forecast $2.9 billion budget).

Response:

As described in 2-7 above the Customary spend budget was set before P/F and has now been adjusted down to $3.4B to remove those items covered by P/F.

Customary spend covers new customer connects, Circuit and substation capacity increases for load growth, Lighting, Restoration maintenance, Integrity programs such as pole replacement and UG cable replacements, and reliability programs. The customary $3.4B will continue to include a level of spend in all these categories as represented in the pie charts on pgs. 9 and 11 of the Simpson testimony consistent with the historical spend.

P/F is incremental spend focused strictly on reliability. The scope of Power Forward includes work streams that are new and not part of routine T&D customary spend. The company will differentiate between the routine and GRR Rider installation by aligning the scope and work plans associated with each to distinct accounting code block that captures these costs separately, where practical.

Many of the projects within the Transmission and Distribution “Hardening and Resiliency” or H/R work scope such as Transformer Retrofit, Deteriorated Conductor, and Circuit Sectionalization, to name a few, already exist and will continue to have a customary level of base funding. Therefore, the charges will be delineated between T&D customary and Power Forward based on a set customary spend level threshold.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**))))**

DIRECT TESTIMONY OF CAROLINE GOLIN ON BEHALF OF NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-6

Duke Energy Carolinas Response to
Eighth Data Request of NCSEA
Data Request No. 8-12

Docket No. E-7, Sub 1146

Date of Request:	**December 20, 2017**
Date of Response:	**January 3, 2018**

☐ **CONFIDENTIAL**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 8-12, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 8-12

Request:

On page 15 of his rebuttal testimony in Docket No. E-2, Sub 1142, Witness Simpson testifies, “the 10-year timeframe covered by these investments is long enough that the range of potential outcomes would add little to the decision-making process.” Please provide all data, analysis, studies, and reports explaining the “range of potential outcomes” from the Company’s proposed Power/Forward investments.

Response:

This assertion was made based on the logical nature of dynamic, complex systems. The Duke Energy Carolinas grid is acted upon by a variety of external forces, such as human intervention, water, flooding, high winds, et cetera. As a result, the Company projects that the Power/Forward investments will improve the reliability of the grid by 40-60% versus taking no action beyond normal spend.

North Carolina

			D
Program Description	**Unit**	**Cost/Unit**	**# Units**
Transformer Retrofit	Cutouts	$1,152	7,000
Cable Replacement	Miles	$148,685	2,822
Sectionalization beyond SOG	Circuits	$20,000	1,008
Deteriorated Conductor Replacement / line rebuild	Miles	$100,000	3,145
Societal Impact Zones	Locations	$5,000,000	15
Pole Inspection & Replacement Backlog Elimination	Poles	$3,333	15,395
Capacity not covered by SOG and Transmission Priorities	Substations	$10,000,000	21
Live front switchgear and transformer replacement	# devices replaced	$25,000	1,248
Hazard Tree Removal		$1,000	14,400
Feeder Ties Unrelated to SOG (for long duration outages)	Miles	$250,000	2,000
Oil filled reclosers replacement	Reclosers	$50,000	528
UG Riser Retrofit		$1,000	34,560
Tripsaver	Reclosers	$6,500	528
Hardening and resiliency programs requiring further engineering and scoping			
	10-Year NC Total		**DEC**
		Grand Total $ M	

EC	DEP	
Total $M	# Units	Total $M
$8.1	344,000	$396.3
$419.6	1,681	$249.9
$20.2	739	$14.8
$314.5	3,520	$352.0
$75.0	8	$40.0
$51.3	9,171	$30.6
$210.0	6	$60.0
$31.2	915	$22.9
$14.4	10,560	$10.6
$500.0	750	$187.5
$26.4	387	$19.4
$34.6	25,344	$25.3
$3.4	387	$2.5
$231.2		$135.8
$1,939.8	DEP	$1,547.5
M	$3,487.3	

Transmission NC and SC

Category	Program Description	DEC	
		# Units	Cost/Unit
Sub H&R	Replace T-Oil Breakers w/Gas	350	$300,000
Sub H&R	Replace Westinghouse SFA 230kV SF6 Breakers	50	$600,000
Sub H&R	Replace SFA 500kV Breakers	17	$895,000
Sub H&R	Replace D-Oil Breakers	500	$125,000
Sub H&R	Replace CCVTs 25+ or older	300	$22,000
Sub H&R	Replace RTU Replacement	50	$150,000
Sub H&R	Replace SBC Breaker Failure Relays	140	$150,000
Sub H&R	Replace Electro-mechanical Relays per Terminal	490	$300,000
Sub H&R	Hybrid Relay Group scheme		
Sub H&R	Replace SEL 121/221 First Gen Relays	550	$180,000
Sub H&R	Install new Digital Fault Recorder (DFR)	3	$250,000
Sub H&R	Replace Digital Fault Recorder (DFR)	15	$250,000
Sub H&R	Replace Line Relay Carriers/Transfer Trip	15	$400,000
Sub H&R	Battery Bank Replacement		
Sub H&R	Replace GE Type U Bushings (count per transformer)	200	$100,000
Sub H&R	ABB O+C Bushings (count per transformer)		
Sub H&R	Replace Transformers - 1 PH & 3 PH	100	$2,000,000
Sub H&R	Replace Trench Reactors		
Sub H&R	Upgrade Load Tap Changer (LTC)	15	$300,000
Sub H&R	Replace Silica Carbide Arresters	2500	$24,000
Sub H&R	Replace Voltage Regulators - 1PH	15	$70,606
Sub H&R	Replace Voltage Regulators - 3PH	10	$240,000
Sub H&R	Replace Cap & Pin Insulators Bus Supports & Standoffs	4000	$25,000
Sub H&R	Upgrade Transformer Coolers	21	$300,000
Sub H&R	Emergent Equipment Replacements	10	$12,000,000
Sub H&R	Replace S&C Substation Circuit Switchers		
Sub H&R	Replace OB Arresters		
Sub H&R	Wood Substations, Rebuild (incremental cost of wood)		
T-Line H&R	Wood Pole Replacement	5000	$25,000
T-Line H&R	T-Line Rebuilds (Per Mile)	100	$1,500,000
T-Line H&R	T-Line Static Replacements (Per Mile)	200	$150,000
T-Line H&R	T-Line Str/Tower Replacements	100	$189,000
T-Line H&R	Replace T-Line Switches	100	$250,000
T-Line H&R	Replace Cap & Pin Insulators Switches	400	$25,000
T-Line H&R	Replace Polymer Insulators with Porcelain (Per Mile)	50	$200,000
			DEC Total:
			Grand Tota

	DEP		
Total $M	# Units	Cost/Unit	Total $M
$105.0	198	$300,000	$59.4
$30.0			
$15.2	6	$895,000	$5.4
$62.5	350	$125,000	$43.8
$6.6	700	$22,000	$15.4
$7.5	84	$150,000	$12.6
$21.0			
$147.0	350	$300,000	$105.0
	116	$100,000	$11.6
$99.0	35	$180,000	$6.3
$0.8	10	$250,000	$2.5
$3.8	23	$250,000	$5.8
$6.0	27	$400,000	$10.8
	300	$15,000	$4.5
$20.0	79	$102,000	$8.1
	100	$102,000	$10.2
$200.0	100	$2,000,000	$200.0
	46	$119,000	$5.5
$4.5			
$60.0	250	$22,000	$5.5
$1.1			
$2.4	71	$350,000	$24.9
$100.0			
$6.3			
$120.0	10	$12,000,000	$120.0
	70	$150,000	$10.5
	44	$22,000	$1.0
	48	$1,500,000	$72.0
$125.0	5000	$25,000	$125.0
$150.0			
$30.0	300	$150,000	$45.0
$18.9	420	$189,000	$79.4
$25.0	132	$250,000	$33.0
$10.0	20	$250,000	$5.0
$10.0			
$1,387		**DEP Total:**	**$1,027.9**
al $ M:	**$2,415.4**		

SOG - North Carolina

Program Description	Unit	Cost/Unit	DEC # Units	DEC Total $M
Automation	Automated Switches	$50,000	3,550	$177.5
Capacity & Connectivity	Circuit	$650,000	960	$624.0
	10-Year NC Total		**DEC**	**$801.5**
		Grand Total $M		

DEP	
# Units	Total $M
2,100	$105.0
540	$351.0
DEP	**$456.0**
$1,257.5	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-7

Duke Energy Carolinas Response to
Eighth Data Request of NCSEA
Data Request No. 8-11

Docket No. E-7, Sub 1146

Date of Request:	**December 20, 2017**
Date of Response:	**January 3, 2018**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 8-11, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 8-11

Request:

On page 7 of his rebuttal testimony in Docket No. E-2, Sub 1142, Witness Simpson testifies, “The (Power/Forward) plan was developed with a very specific goal: to reduce events by 30 to 40 percent and SAIDI and SAIFI scores by 40 to 60 percent.” Please provide all data, analysis, studies, reports, or other evidence demonstrating how the Company’s proposed investments will achieve this reliability improvement goal. Please provide this data in Excel format with all formulas and links intact, where appropriate.

Response:

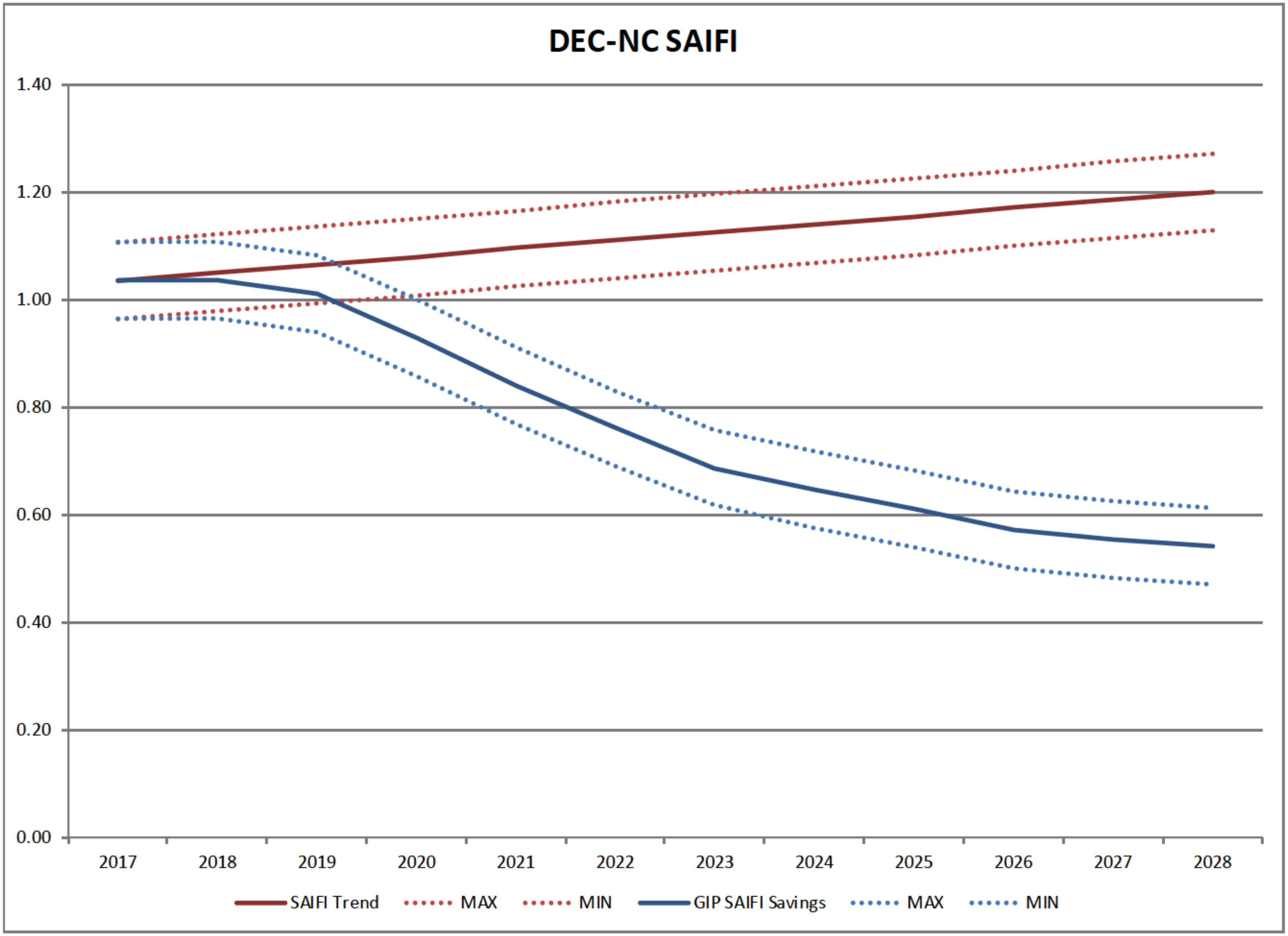
Please see “NCSEA 8-11 Reliability Trends and Improvement.xlsx”.

NCSEA 8-11
Re iabi ity Trends and

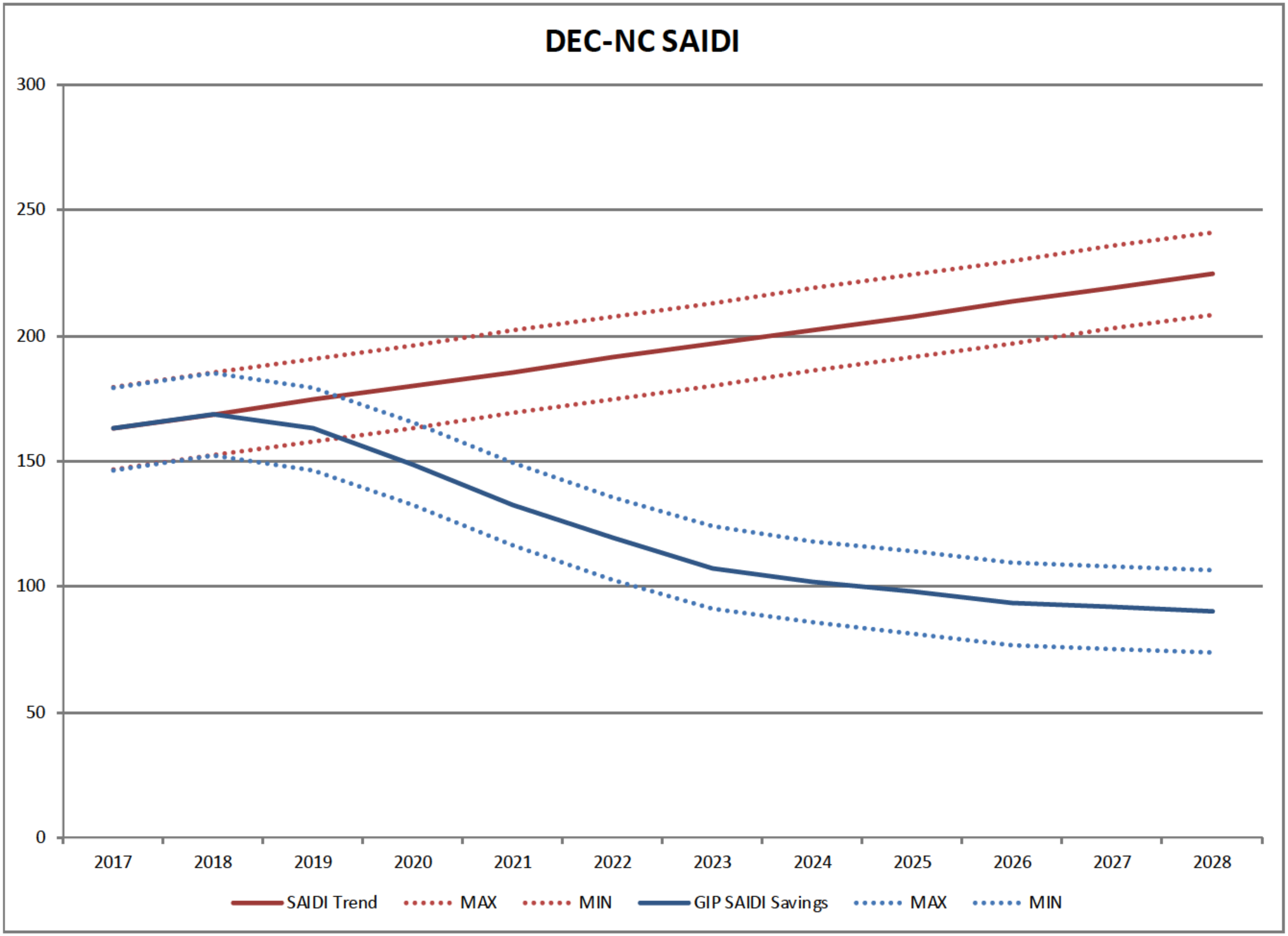
DEC-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIFI Trend	1.04	1.05	1.07	1.08	1.10	1.11	1.13	1.14	1.16	1.17	1.19	1.20	0.06	0.07
MAX	1.11	1.12	1.14	1.15	1.17	1.18	1.20	1.21	1.23	1.24	1.26	1.27		
MIN	0.96	0.98	0.99	1.01	1.02	1.04	1.05	1.07	1.08	1.10	1.11	1.13		
GIP SAIFI Savings	1.04	1.04	1.01	0.93	0.84	0.76	0.69	0.65	0.61	0.57	0.55	0.54		
MAX	1.11	1.11	1.08	1.00	0.91	0.83	0.76	0.72	0.68	0.64	0.62	0.61		
MIN	0.96	0.97	0.94	0.86	0.77	0.69	0.62	0.57	0.54	0.50	0.48	0.47		

DEC-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIDI Trend	163	169	174	180	185	191	197	202	208	213	219	225	12.80	16.41
MAX	179	185	191	196	202	207	213	219	224	230	235	241		
MIN	147	152	158	163	169	175	180	186	191	197	203	208		
GIP SAIDI Savings	163	169	163	149	133	119	107	102	98	93	92	90		
MAX	179	185	179	165	149	136	124	118	114	110	108	106		
MIN	147	152	147	132	116	103	91	85	81	77	75	74		

DEC-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2012-2016 Std Dev	80% CI
EVENTS Trend	48,849	50,559	52,269	53,978	55,688	57,397	59,107	60,817	62,526	64,236	65,945		3,111.09	3,988.41
MAX	52,838	54,547	56,257	57,967	59,676	61,386	63,095	64,805	66,515	68,224	69,934			
MIN	44,861	46,571	48,280	49,990	51,699	53,409	55,119	56,828	58,538	60,247	61,957			
GIP EVENTS Savings	48,849	50,559	52,063	52,814	52,920	51,863	50,340	48,783	47,251	44,816	43,621			
MAX	52,838	54,547	56,052	56,802	56,908	55,852	54,328	52,771	51,239	48,804	47,609			
MIN	44,861	46,571	48,075	48,825	48,932	47,875	46,352	44,795	43,262	40,828	39,633			



DEC-NC SAIFI
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2017
2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
2028
SAIFI Trend
MAX
MIN
GIP SAIFI Savings
MAX
MIN



DEC-NC SAIDI
300
250
200
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100
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2017
2018
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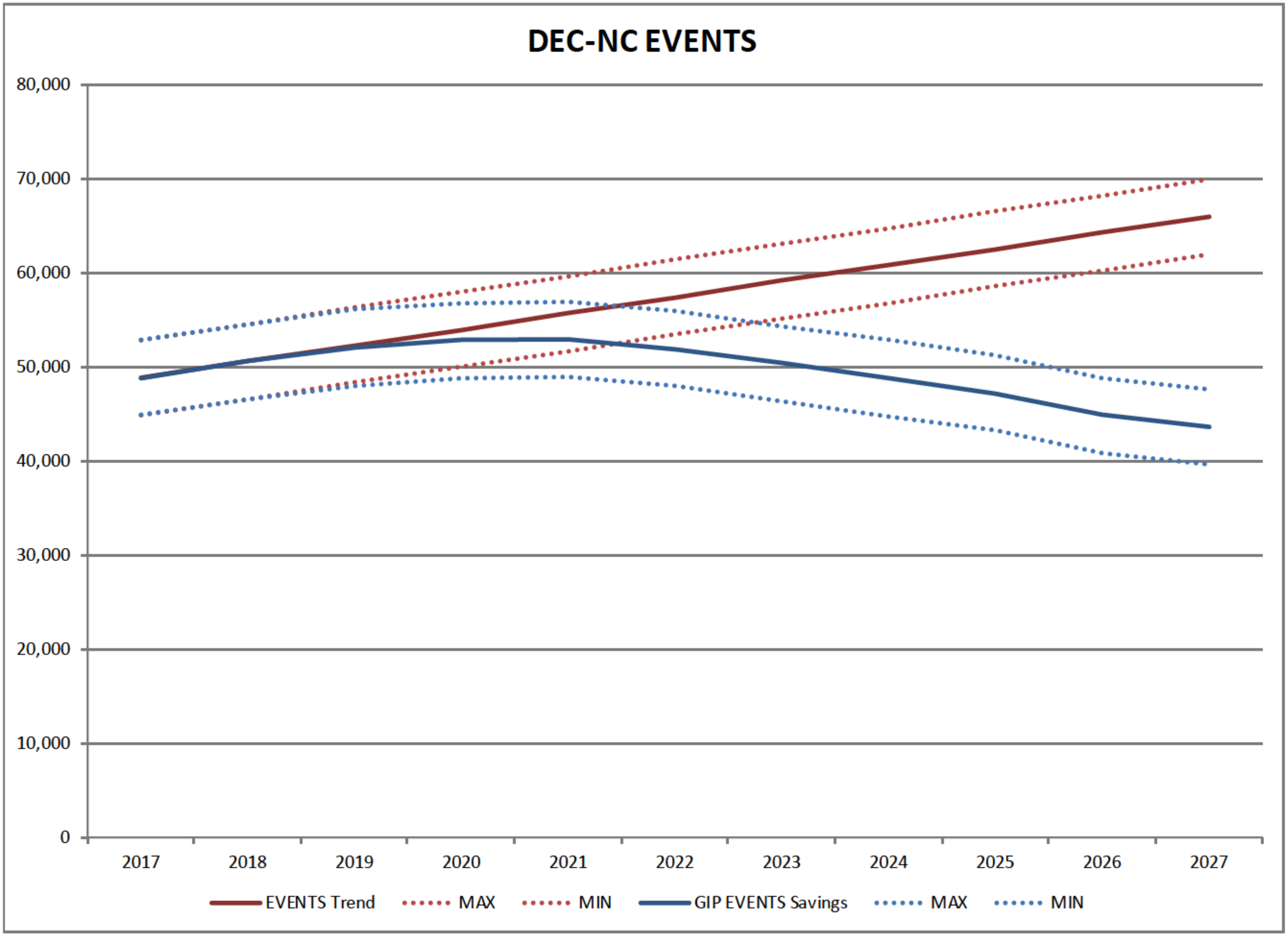
2020
2021
2022
2023
2024
2025
2026
2027
2028
SAIDI Trend
MAX
MIN
GIP SAIDI Savings
MAX
MIN


DEC-NC EVENTS
80,000
70,000
60,000
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40,000
30,000
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10,000
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2017
2018
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2020
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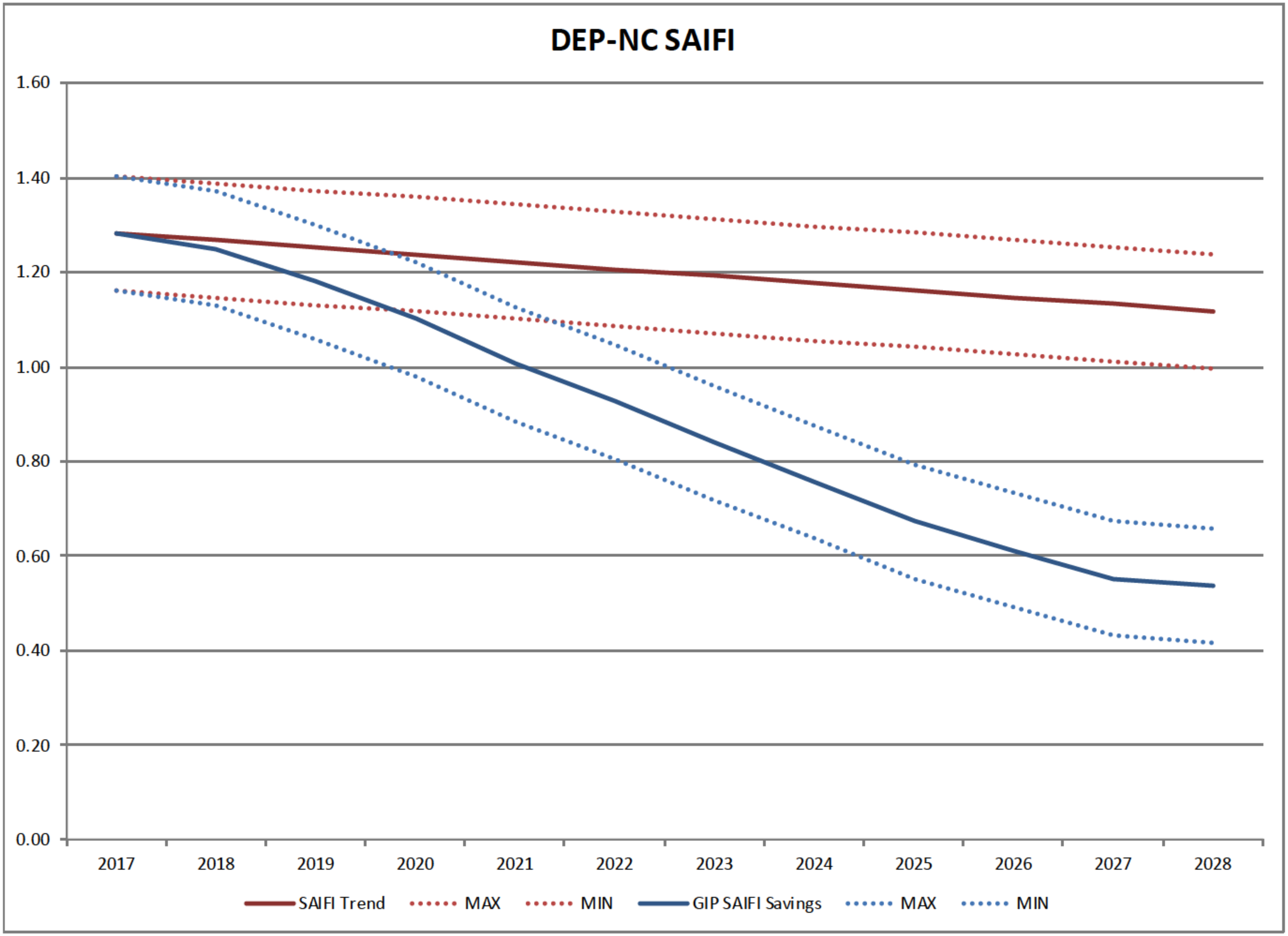
2023
2024
2025
2026
2027
EVENTS Trend
MAX
MIN
GIP EVENTS Savings
MAX
MIN

DEP-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIFI Trend	1.28	1.27	1.25	1.24	1.22	1.21	1.19	1.18	1.16	1.15	1.13	1.12	0.09	0.12
MAX	1.40	1.39	1.37	1.36	1.34	1.33	1.31	1.30	1.28	1.27	1.25	1.24		
MIN	1.16	1.15	1.13	1.12	1.10	1.09	1.07	1.06	1.04	1.03	1.01	1.00		
GIP SAIFI Savings	1.28	1.25	1.18	1.10	1.00	0.93	0.84	0.76	0.67	0.61	0.55	0.54		
MAX	1.40	1.37	1.30	1.22	1.13	1.05	0.96	0.88	0.79	0.73	0.67	0.66		
MIN	1.16	1.13	1.06	0.98	0.88	0.80	0.72	0.64	0.55	0.49	0.43	0.42		

DEP-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2012-2016 Std Dev	80% CI
SAIDI Trend	152	158	165	171	178	184	191	197	204	210	217	223	16.11	20.65
MAX	173	179	186	192	199	205	212	218	225	231	238	244		
MIN	131	138	144	151	157	164	170	177	183	190	196	203		
GIP SAIDI Savings	152	158	149	142	131	124	116	109	101	97	94	92		
MAX	173	179	170	163	152	145	137	129	121	118	115	113		
MIN	131	138	129	121	111	104	95	88	80	77	73	72		

DEP-NC	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027		2012-2016 Std Dev	80% CI
EVENTS Trend	45,916	48,176	50,436	52,696	54,956	57,215	59,475	61,735	63,995	66,255	68,514		4,212.14	5,399.96
MAX	51,316	53,576	55,836	58,096	60,356	62,615	64,875	67,135	69,395	71,655	73,914			
MIN	40,516	42,776	45,036	47,296	49,556	51,815	54,075	56,335	58,595	60,855	63,114			
GIP EVENTS Savings	45,916	48,176	50,388	51,616	52,604	52,478	51,004	49,692	47,845	46,424	45,271			
MAX	51,316	53,576	55,788	57,016	58,004	57,878	56,404	55,092	53,245	51,824	50,671			
MIN	40,516	42,776	44,988	46,216	47,204	47,078	45,604	44,292	42,445	41,024	39,871			


DEP-NC SAIFI
1.60
1.40
1.20
1.00
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0.60
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0.20
0.00
2017
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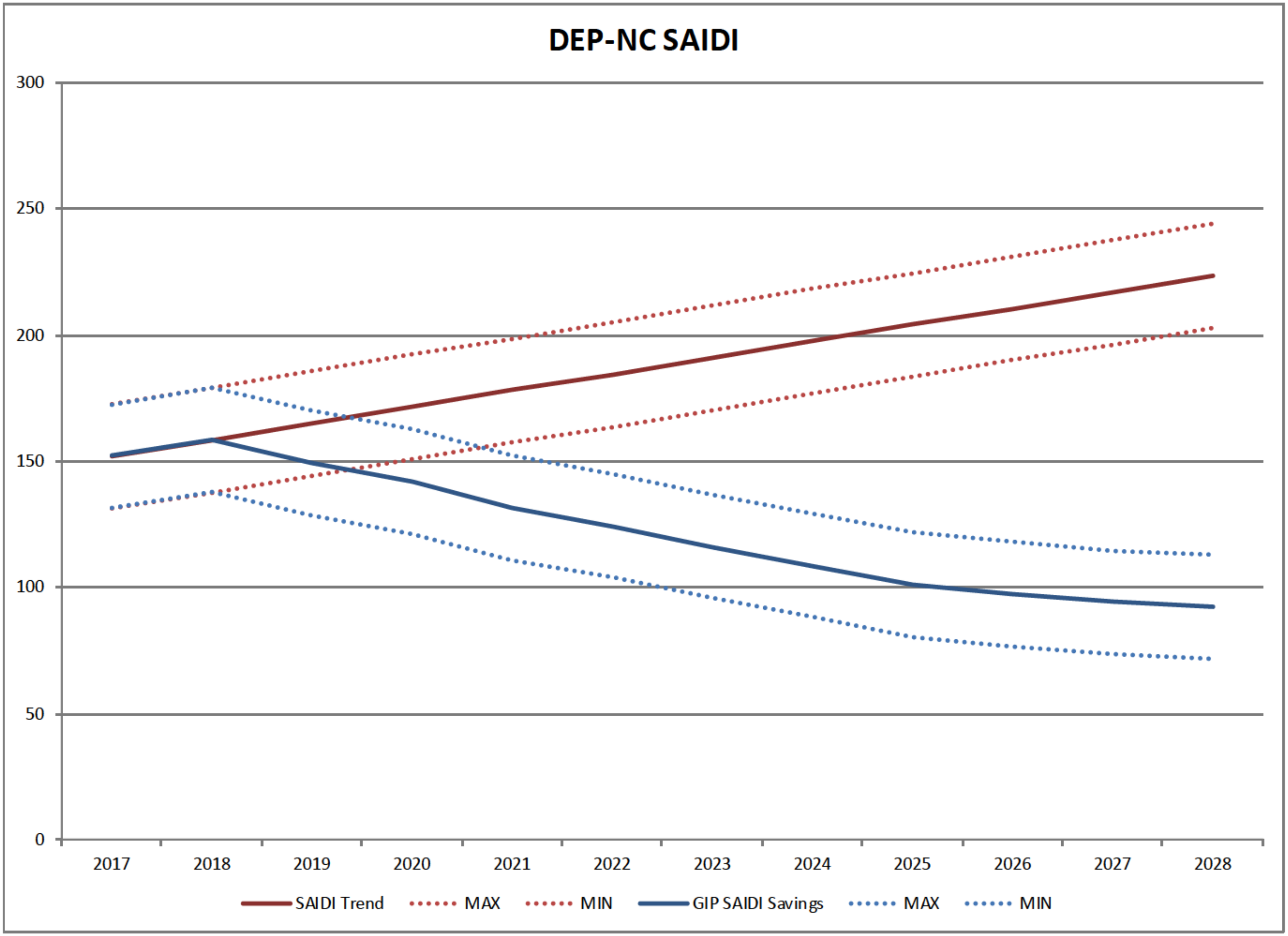
2028
SAIFI Trend
MAX
MIN
GIP SAIFI Savings
MAX
MIN


DEP-NC SAIDI
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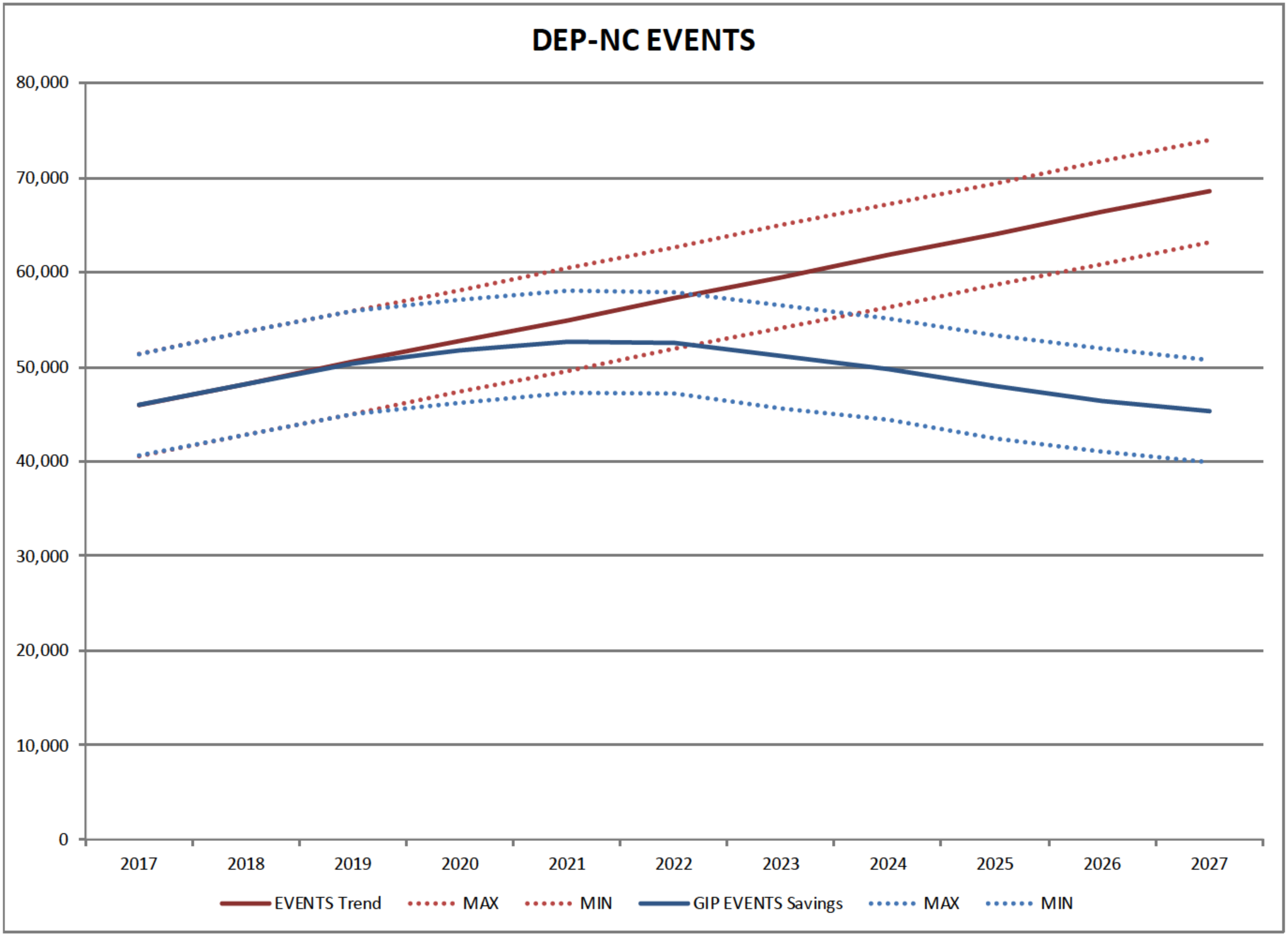
2024
2025
2026
2027
2028
SAIDI Trend
MAX
MIN
GIP SAIDI Savings
MAX
MIN



DEP-NC EVENTS
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
0
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2018
2019
2020
2021
2022
2023
2024
2025
2026
2027
EVENTS Trend
MAX
MIN
GIP EVENTS Savings
MAX
MIN

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**))))**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-8

Duke Energy Carolinas
Response to
NC Public Staff Data Request
Data Request No. NCPS 56-15

Docket No. E-7, Sub 1146

Date of Request:	**November 16, 2017**
Date of Response:	**November 27, 2017**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

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The attached response to NC Public Staff Data Request No. 56-15, was provided to me by the following individual(s): Melissa B. Culbreth, Director, Distribution Operations Finance, Regulated Utilities Finance, and was provided to NC Public Staff under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 56
DEC Docket No. E-7, Sub 1146
Item No. 56-15

NCPS 56-15

Request:

Please provide all cost benefit analyses related to any projects proposed to be included in the proposed GRR Rider.

Response:

The Company developed the Power Forward Carolinas - Executive Technical Overview, which incorporated an EY economic impact analysis, to outline the costs and benefits for the Power/Forward programs as a whole.

See attached:

"PSDR 56-15 EY QUEST Duke Energy NC PowerForward Impact.pdf"

PDF
PSDR 56-15 EY
QUEST Duke Energy N

"PSDR 56-15 Power Forward Carolinas - Executive Technical Overview.pdf"

PDF
PSDR 56-15 Power
Forward Caro inas - E

North Carolina impacts of Duke Energy's Power/Forward grid improvement program

Prepared for Duke Energy by EY Quantitative Economics and Statistics (QUEST)

November 2017

Building a better working world

The accompanying analyses were prepared for the use of Duke Energy. The analyses conducted in this report constitute neither an examination nor a compilation of prospective financial statements nor the application of agreed-upon procedures thereto in accordance with the attestation standards established by the American Institute of CPAs (AICPA). Accordingly, EY does not express an opinion on or offer any other assurances as to whether the analyses are presented in conformity with AICPA presentation guidelines or as to whether the underlying assumptions provide a reasonable basis for the analyses.

Executive summary

This study presents the potential economic impacts related to Duke Energy's proposed Power/Forward grid improvement program in North Carolina, which includes investments for the proposed self-optimizing grid, conversion of targeted areas to underground lines, and distribution network hardening and resiliency. This study includes estimates of the temporary economic impacts during the investment period as well as the ongoing benefits to businesses and households from increased electric grid reliability.

Duke Energy will invest an estimated $13.84 billion for facility and grid improvements, supporting jobs and economic activity over the next 10 years related to purchases of construction services, equipment, and increased headcount related to the investment.[1] These impacts occur as additional construction, installation, and maintenance workers are hired to undertake the significant task of hardening the North Carolina energy grid and as Duke Energy invests in on installation/construction services and domestically-sourced materials and equipment. These impacts are described as "one-time" because they do not recur. The total impacts over the investment period are summarized in Table ES-1 ("Duke Energy capital expenditures" column) and Table ES-2.

Power/Forward will also result in increased electricity reliability for Duke Energy's customers. Duke Energy forecasts that outage events will be less frequent and shorter in duration as a result of the infrastructure improvements, with a 40-60% reduction in regular-service outages and an estimated 30% reduction in the frequency and duration of major event outages.[2]

These reductions in outage events and severity will provide more consistent electric service to Duke Energy's customers throughout North Carolina, which will reduce interruption losses, increase productivity, and reduce overall business and household costs associated with outages. These impacts will continue after the investment period. The total impacts over the investment period are summarized in Table ES-1 ("Reliability improvements" column) and Table ES-3.

Table ES-1. Statewide impacts of Duke Energy's Power/Forward program
Millions of 2017 dollars; Totals over the investment period

	Duke Energy capital expenditures	Reliability improvements	Statewide total impacts
Statewide impacts (11-year total)			
Average employment*	11,791	7,259	19,051
Economic output (11 yr. total)	$20,029	$12,905	$32,934
GDP (11 yr. total)	$13,753	$6,602	$20,356
Labor income (11 yr. total)	$9,508	$4,806	$14,313
State & local taxes (11 yr. total)	$1,169	$421	$1,590

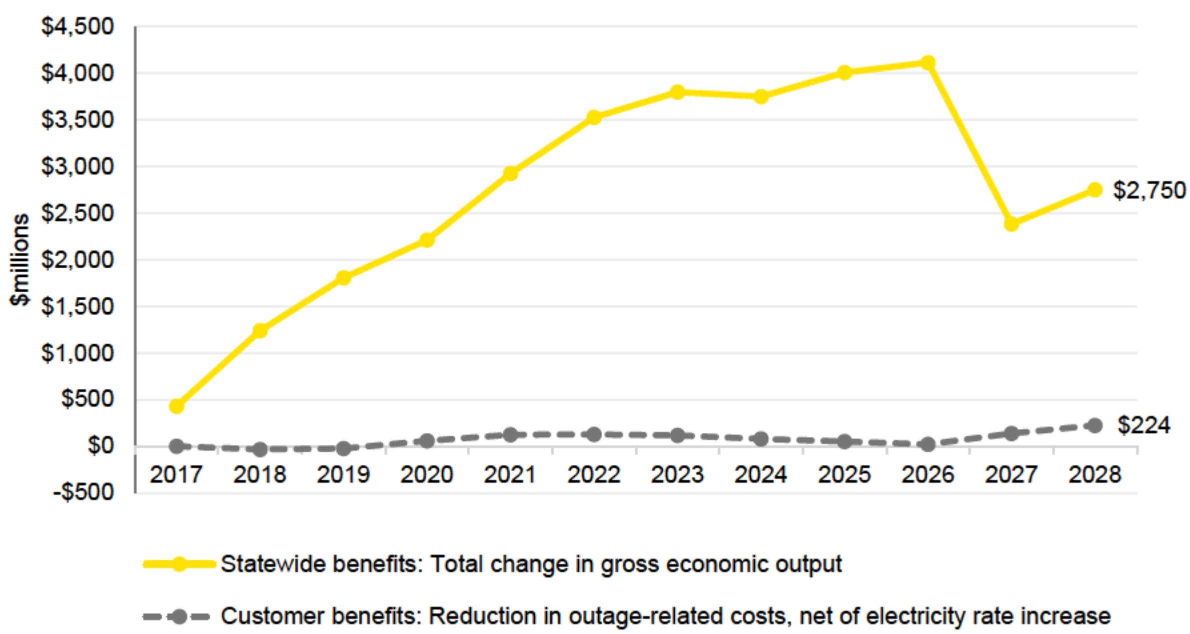
*Average jobs in place in each year.
Note: Figures may not appear to sum due to rounding; Source: Duke Energy management; EY analysis.

[1] Includes $13.3 billion of capital investments in installation and equipment and an additional $500 million of incremental project-related operations and maintenance expenditures.
[2] Projections of reliability improvements provided by Duke Energy management.

Figure ES-1 summarizes the annual impacts in the state:

- **Net benefits for Duke Energy customers:** Reliability improvements for regular service and major events could result in an estimated $1.67 billion in avoided costs annually for North Carolina businesses and households, once the project is complete (2028). Businesses and households will necessarily experience an increase in rates as result of this investment. The annual net benefit to businesses and households after considering this cost increase will reach an estimated $224 million by the end of the project, averaging $80 million per year over the investment period (dashed line in Figure ES-1).
- **Statewide GDP impact:** The analysis quantifies the statewide economic impacts as the effects of Duke Energy's project expenditures and increased electricity reliability flow through the economy.
  - Duke Energy's capital investments will generate $20.03 billion of total economic output in North Carolina, reflecting the share of total expenditures supplied by North Carolina businesses. Of this amount, $13.75 billion will be North Carolina GDP and $6.28 billion will be business-to-business sales (purchases from suppliers).
  - Businesses will respond to lower production costs (positive net benefits) through additional purchases of operating inputs and payments to employees. This activity will support an estimated $12.91 billion of total economic output. Of this amount, $6.60 billion will be North Carolina GDP.
  - **Combined, this economic activity will drive a cumulative impact of $32.93 billion in North Carolina economic output over the 12-year project period from 2017 through 2028 – averaging $2.75 billion per year (solid yellow line in Figure ES-1).**

Figure ES-1. Quantifying the North Carolina impacts of Duke Energy's Power/Forward program
Millions of real 2017 dollars



Note: Includes benefits related to normal-service and MED reliability improvements
Source: Duke Energy management; EY analysis.

Additional key findings:

- Duke Energy's capital expenditures will support an average of **11,791 jobs in North Carolina** over the 10-year investment period (including direct, indirect, and induced effects).
- **Duke Energy will employ an average of 6,200 direct workers (Duke Energy employees and contractors) during each year of the investment period.** Primarily linemen, these jobs will be high-wage, high-skill positions in North Carolina. Duke Energy's investment will require more linemen than are currently employed in the state.[3]
- **Direct employees will earn an average of $110,000 in annual compensation, including the value of wages and benefits.** The direct compensation includes $82,000 of base wages/salaries and $28,000 of benefits. Duke Energy's base wage is 75% higher than the statewide average of $46,500.[4] Over the 10-year period, these employees will earn an estimated **$6.93 billion in personal income.**
- For every 10 direct jobs, 9 additional jobs are supported elsewhere in the state through indirect and induced economic activity – **statewide employment multiplier of 1.9**.
- Additional economic activity related to reliability improvements will support an estimated average of 7,259 jobs during the investment period, including indirect and induced economic activity.
- **During the project period, Duke Energy's capital investments and activity related to reliability improvements will generate nearly $1.59 billion in state and local tax revenues.** Of this total, an estimated $513 million will be direct taxes paid by Duke Energy, including $330 million of state and local sales taxes on electrical equipment and installation materials.

Table ES-1. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of real 2017 dollars

	Direct: Duke Energy	Indirect & Induced	Total
Total capital investment impacts			
Average employment*	6,201	5,590	11,791
Economic output	$11,559	$8,470	$20,029
GDP	$9,066	$4,688	$13,753
Labor income	$6,925	$2,583	$9,508
State & local taxes	$921	$248	$1,169

*Average jobs in place in each year.
Note: Figures may not appear to sum due to rounding.
Source: Duke Energy management; EY analysis.

[3] In 2015, there were 4,760 electrical line installers and repairers employed in North Carolina. See: US Bureau of Labor Statistics (BLS). Occupational Employment Statistics (OES).
[4] Average wage across all industries. See: US BLS. Quarterly Census of Employment and Wages (QCEW).

Table ES-2. Dynamic economic impacts of improved electric infrastructure relability
Millions of 2017 dollars

	Year 5 2022	Year 11 2028	Cumulative 11-yr. total
Dynamic impacts of reliability improvements			
Employment	5,658	15,256	7,259
Economic output	$806	$2,750	$12,905
GDP	$407	$1,434	$6,602
Labor income	$313	$981	$4,806
State & local taxes	$26	$89	$421

*Average jobs in place in each year.
Source: Duke Energy management; EY analysis.

Contents

Glossary of key terms

- **Backward linkage:** Links an industry to its suppliers or a household (an institution) and the producers of household goods and services.
- **Direct coefficients:** For each dollar outlay for a given industry, the amount used for purchase of goods and services from each industry sector modeled.
- **Economic output:** Economic output is the broadest measure of economic activity and includes value added and total intermediate input purchases (supplier purchases). For most industries, economic output is equivalent to total revenues (production value).
- **Employment:** Employment comprises estimates of the number of jobs, full-time plus part-time, by place of work. Full-time and part-time jobs are counted at equal weight. Employees, sole proprietors, and active partners are included, but unpaid family workers and volunteers are not included.
- **Gross Domestic Product (GDP):** GDP, or value added, includes labor income, indirect business taxes, consumption of fixed capital (depreciation), and mixed income.
- **Indirect effects:** Indirect effects are related to purchases from local suppliers and the subsequent rounds of supplier purchases in the local economy.
- **Induced effects:** Induced effects are related to household consumption spending by direct and indirect employees.
- **Input-output accounts:** The accounting of all current money flows from and to (outlays and outputs) industries and institutions located within the region.
- **Labor income:** All wages, salaries, and benefits (including employer-paid payroll tax/social insurance) received by employees. Labor income includes earnings of proprietors (self-employed income).
- **RPC (Regional purchase coefficients):** The share of goods and services purchased from local suppliers.
- **System Average Interruption Frequency Index (SAIFI):** Total number of sustained (>5 minutes) customer interruptions / Total number of customers served
- **System Average Interruption Duration Index (SAIDI):** customer interruption duration (minutes) / Total number of customers served
- **Taxes:** The estimated tax contribution includes taxes collected by state and local governments throughout North Carolina.

Acronyms and abbreviations

Abbr.	Meaning
C&I	Commercial and industrial
DOE	U.S. Department of Energy
EIA	Energy Information Administration
ICE	Interruption Cost Estimate
IEEE	Institute of Electrical and Electronics Engineers
LBNL	Lawrence Berkeley National Laboratory
MAIFI	Momentary Average Interruption Frequency Index
MED	Major event day
OE DOE	Office of Electricity Delivery and Energy Reliability
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index

North Carolina impacts of Duke Energy's Power/Forward program

Duke Energy is proposing to invest $13.84 billion for facility and grid improvements in North Carolina as part of a project that will generate economic benefits throughout the state.[5] These benefits occur in two ways.

First, as Duke Energy makes expenditures related to construction activities and equipment purchases, those dollars support jobs and wages in the state. These impacts occur as a result of the project itself, including the workers involved in undergrounding lines, installing equipment, and the other necessary activities and expenditures related to executing the program's objectives.

In addition to these temporary benefits from the program activities, there are long-term benefits from achieving the program's reliability objectives. As Duke Energy's business and household customers enjoy increased electric reliability due to the improved grid, those customers have reduced costs which create a more favorable environment for business investment and job growth.

Combined, these two types of impacts will support nearly $33 billion of gross state economic output (business production), generating $20 billion of state GDP from 2017 through 2028. Of this GDP impact, an estimated $14 billion will be labor income earned by employees at Duke Energy, as well as employees at Duke Energy contractors, suppliers, customers, and other North Carolina businesses. The economic impacts in this report are expressed in terms of five indicators.

- **Economic output:** Economic output is the broadest measure of economic activity and includes Gross Domestic Product and intermediate input purchases.
- **Gross Domestic Product (GDP):** GDP, or value added, is a component of economic output and includes labor income, payments to capital, and indirect taxes.
- **Labor income:** Labor income is a component of GDP and includes total employee compensation (value of wages and benefits) and proprietor income.
- **Employment:** Employment reflects the total number of full-time jobs (headcount). Direct installation labor is expressed in terms of full-time equivalents (FTEs), including Duke Energy employees and contractors.
- **State and local taxes:** Estimated tax impacts include individual and corporate income taxes, sales and excise taxes, and local property taxes. Income, property, and sales taxes paid by Duke Energy employees (including contractors) on their incomes and purchases are included as direct taxes.

[5] Includes $13.3 billion of capital expenditures for installation and electrical equipment and an additional $500 million in incremental project-related operations and maintenance expenditures. Specifically, the analysis considers reliability improvements related to a self-optimizing grid, converting targeted areas to underground lines, and distribution network hardening and resiliency.

Part 1: Quantifying the potential impacts in North Carolina of Duke Energy's capital improvements

1. Overview

Duke Energy will invest more than $13.84 billion in North Carolina to upgrade, modernize, and expand its grid capacity in the state – including $13.31 billion in installation and equipment and an additional $530 million in incremental project-related operations and maintenance costs. This investment will temporarily support jobs and incomes in North Carolina. These contributions are referred to as "one-time" effects because they do not recur. This analysis considers impacts related to:

(1) **10-year impacts of construction & installation** – Duke Energy's planned capital expenditures will temporarily support workers in North Carolina, primarily in the power and communications construction sector.

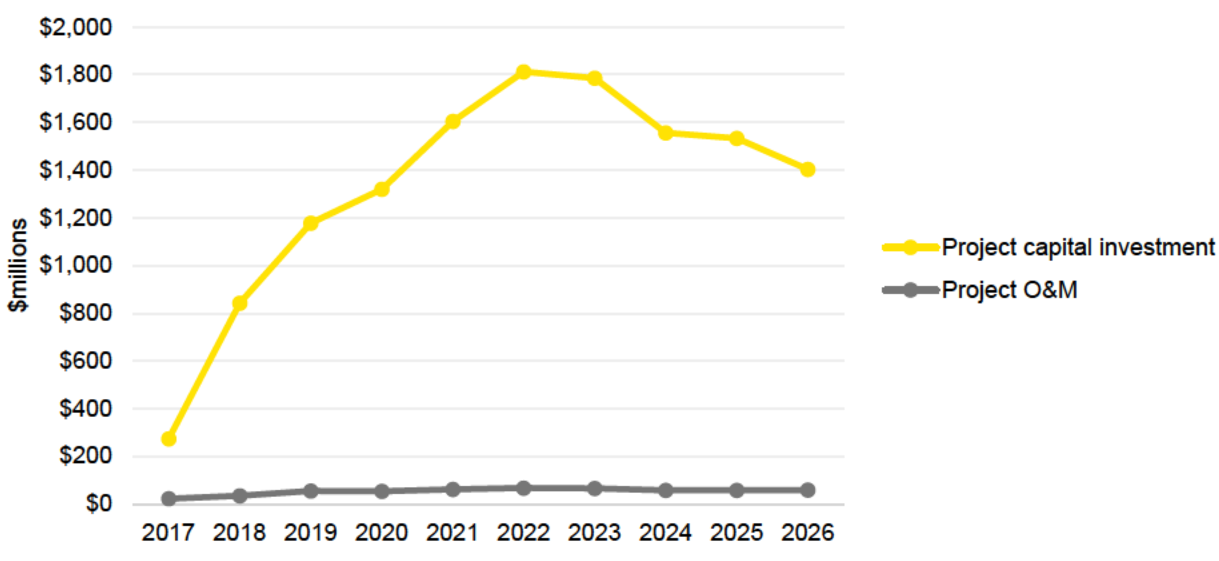
(2) **10-year impacts of equipment purchases** – A portion of Duke Energy's required equipment will be sourced within North Carolina, temporarily supporting manufacturing jobs.

(3) **10-year impacts of incremental (project-related) operations and maintenance** – Incremental operations and maintenance related to the planned infrastructure improvements will support ongoing jobs and incomes across North Carolina.

Figure 1 shows the planned expenditures for project capital investment and project-related operations and maintenance expenditures, by year. Investment will peak in 2022.

Figure 1. North Carolina Power/Forward expenditures, by year

Millions of 2017 dollars



Source: Data provided by Duke Energy management.

Table 1 shows the total impacts over 10 years as a result of Duke Energy's expenditures on the Power/Forward program. Detailed results are presented in the next section. Overall, the program will support an average of 11,791 jobs in North Carolina for ten years and generate a total of $20.03 billion in statewide economic output. Of this economic output impact, $13.75 billion will be state GDP.

Table 1. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of 2017 dollars

	Direct: Duke Energy	Indirect	Induced	Total
Average annual employment	6,201	1,243	4,347	11,791
Worker years	62,014	12,431	43,468	117,912
Economic output	$11,559	$2,508	$5,962	$20,029
GDP	$9,066	$1,284	$3,403	$13,753
Labor income	$6,925	$737	$1,846	$9,508
State taxes	$518	$49	$114	$681
Statewide local taxes	$403	$26	$60	$489

Note: Figures may not appear to sum due to rounding. Worker years are equivalent to the number of jobs lasting an average of one year each.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

2. 10-year impacts related to Duke Energy's planned capital investments

This study estimates three types of economic effects related to capital investments and incremental operating costs:

- **Direct effects** include the temporary installation (engineers and line installers) and ongoing maintenance jobs supported by the planned infrastructure improvement projects throughout the state.
- **Indirect (supplier) economic effects** are the result of the Duke Energy's purchases from in-state suppliers (e.g., construction and installation materials, electrical equipment, etc.) and the subsequent rounds of supplier purchases in the state as Duke Energy's suppliers purchase additional goods and services to meet the increased demand.
- **Induced (employee spending) economic contributions** are related to employee household spending. Duke Energy, contractor, and supplier employees spend a portion of their incomes on goods and services from North Carolina businesses. These transactions support employment at retailers, restaurants, service companies, and other businesses.

Duke Energy's $13.84 billion of project expenditures can be expressed as three components: (1) $11.03 billion for installation materials and labor, generating direct construction sector economic output (See Table 2: Installation direct economic output), (2) $534 million of project operations and maintenance (O&M) expenditures (See Table 2: Operations & maintenance direct economic output), and (3) $2.28 billion for purchases of electrical equipment (the NC-sourced equipment is included in Table 2 as an indirect impact).

Duke Energy will employ an average of 6,201 direct Duke Energy employees and contractors for equipment installation and project-related operations & maintenance. Primarily linemen, these jobs will be high-wage, high-skill positions in North Carolina. Duke Energy's investment will require more linemen than are currently employed in the state.[6] Direct employees will earn an average of $110,000 in total compensation, including the value of wages and benefits. The direct compensation includes $82,000 of base wages/salaries and $28,000 of benefits. Duke Energy's base wage is 75% higher than the statewide average of $46,500.[7]

Nearly one-fifth of Duke Energy's investment will be for purchases of electrical equipment, totaling $2.28 billion over 10 years. Duke Energy estimates that 28% of this equipment will be sourced from North Carolina suppliers – generating $639 million of indirect economic output.

Including indirect (supplier) and induced (household spending) effects, Duke Energy's project-related expenditures will support more than $20.03 billion in total economic output throughout the state (approximately equivalent to business sales). Of the total state economic output impact, more than $13.75 billion will be North Carolina GDP, averaging $1.4 billion. The GDP impact includes $9.51 billion of labor income earned by direct, indirect, and induced employees.

The overall employment multiplier for this activity is 1.90 – for every 10 direct Duke Energy employees and contractors working on-site for installation or operations and maintenance, an additional 9 jobs will be supported elsewhere in the state.

[6] In 2015, there were 4,760 electrical line installers and repairers employed in North Carolina. See: US Bureau of Labor Statistics (BLS). Occupational Employment Statistics (OES).
[7] Average wage across all industries. See: US BLS. Quarterly Census of Employment and Wages (QCEW).

Table 2. 10-year statewide economic impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of 2017 dollars

	Direct: Duke Energy	Indirect	Induced	Total
Installation				
Average annual employment	5,917	939	4,027	10,883
Worker years	59,168	9,387	40,274	108,828
Economic output	$11,025	$1,617	$5,524	$18,166
GDP	$8,650	$856	$3,154	$12,660
Labor income	$6,508	$523	$1,711	$8,743
State taxes	$497	$32	$105	$633
Statewide local taxes	$394	$17	$55	$466
Project operations & maintenance				
Average annual employment	285	58	196	539
Worker years	2,846	583	1,961	5,390
Economic output	$534	$89	$269	$893
GDP	$416	$47	$154	$617
Labor income	$416	$28	$83	$527
State taxes	$21	$2	$5	$28
Statewide local taxes	$9	$1	$3	$13
Equipment purchases				
Average annual employment	--	246	123	369
Worker years	--	2,462	1,232	3,694
Economic output	--	$802	$169	$970
GDP	--	$381	$96	$477
Labor income	--	$186	$52	$238
State taxes	--	$15	$4	$19
Statewide local taxes	--	$8	$2	$10
Total capital investment impacts				
Average annual employment	6,201	1,243	4,347	11,791
Worker years	62,014	12,431	43,468	117,912
Economic output	$11,559	$2,508	$5,962	$20,029
GDP	$9,066	$1,284	$3,403	$13,753
Labor income	$6,925	$737	$1,846	$9,508
State taxes	$518	$49	$114	$681
Statewide local taxes	$403	$26	$60	$489

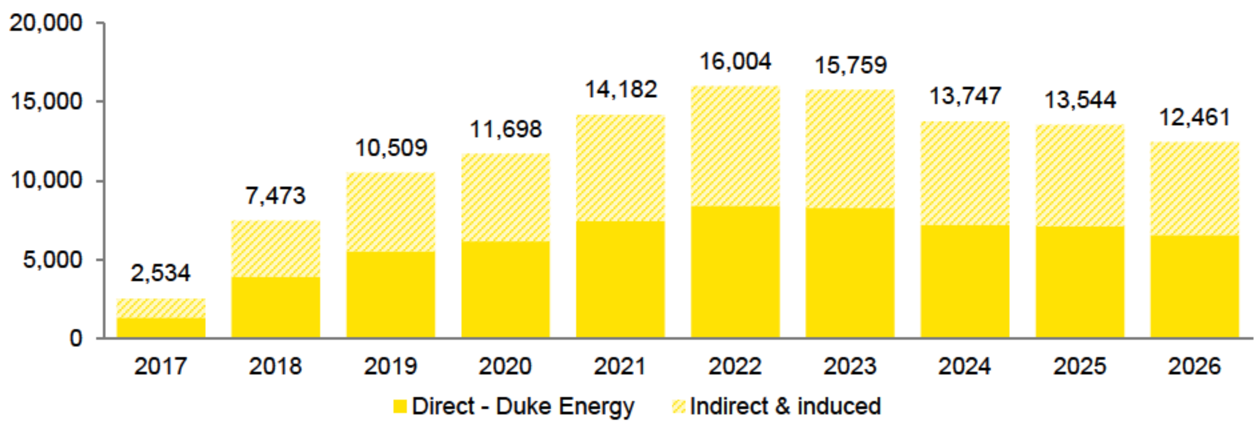
Note: Figures may not appear to sum due to rounding. Worker years are equivalent to the number of jobs lasting an average of one year each.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Figures 1 and 2 show the estimated employment and economic output impacts over each year of the investment period. Including direct, indirect, and induced effects, Duke Energy's project expenditures will support an average of 11,791 jobs – totaling 117,912 "worker years." Worker years are the total number of jobs lasting an average of one year each. These jobs include contractors and engineers, as well as employees at installation material and electrical equipment suppliers. See Figure 1 for the estimated jobs supported in each year of the investment period. Workers supported by capital expenditure impacts will earn an estimated $80,600 in average labor income (total compensation) statewide.

The project expenditures will generate an annual average of $2.00 billion of gross economic output in North Carolina during the 10-year investment period – for a total impact of $20.03 billion (see Figure 2).

Figure 1. North Carolina temporary employment impact of capital expenditures, by year

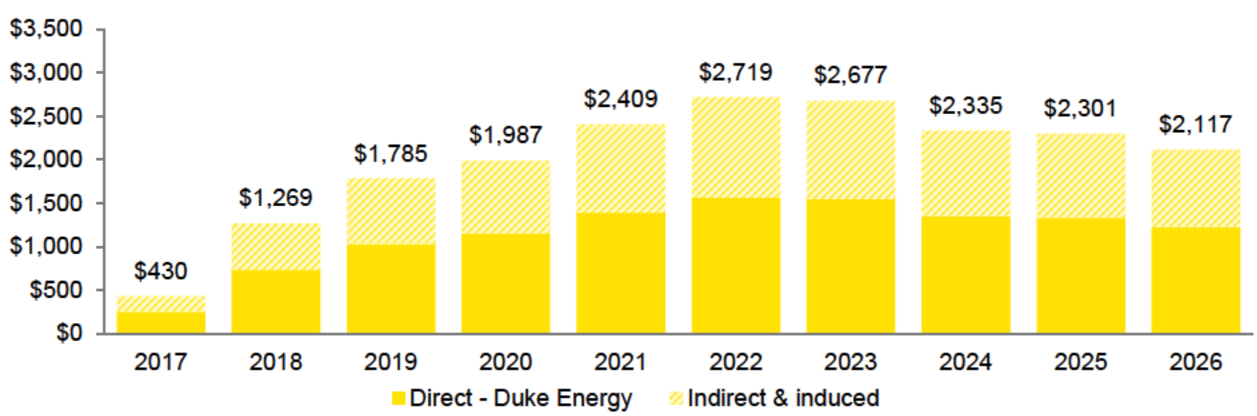
Average statewide employment impact = 11,791 jobs



Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Figure 2. North Carolina gross economic output impact of capital expenditures, by year

Millions of 2017 dollars; Average economic output = $2.0 billion



Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Duke Energy's Power/Forward expenditures will generate an estimated $1.17 billion in public-sector tax revenues throughout North Carolina, including an estimated $388 million in state sales taxes and $262 million in state individual income taxes. See Table 3.

Table 3. 10-year state and local tax impacts related to Duke Energy's Power/Forward program spending (installation, equipment, and O&M)
Millions of 2017 dollars

	Direct tax	Indirect & Induced	Total tax contribution
State taxes			
Sales & use taxes	$319	$70	$388
Personal income	$189	$73	$262
Other taxes	$10	$20	$30
Total state taxes	**$518**	**$163**	**$681**
Local taxes			
Property taxes	$85	$64	$149
Other local taxes, statewide	$135	$21	$156
Total local taxes	**$220**	**$85**	**$306**
Total state & local taxes	**$738**	**$248**	**$986**
Incremental property tax from Increased value of NC assets	$183	--	$183
Total state & local taxes, incl. incremental property taxes	**$921**	**$248**	**$1,169**

Note: Figures may not appear to sum due to rounding.
Source: EY analysis using the IMPLAN input-output multiplier model and data provided by Duke Energy management.

Part 2: North Carolina economic impacts of Duke Energy's improved electric infrastructure reliability

In addition to the temporary impacts of Duke Energy's direct spending presented in Part 1, grid improvements will also promote a stronger state economy by reducing outage-related costs for Duke Energy's customers.

This analysis estimated the economic and tax effects related to a reduction in business and household costs from increased reliability related to the improved and expanded grid. The analysis considers reliability improvements related to integrating a self-optimizing grid, converting targeted areas to underground lines, and distribution network hardening and resiliency.

The impacts in this section are additive to the results presented in Part 1.

3. Direct business and household benefits and costs

This section outlines the estimated direct impact on business and household costs as a result of Duke Energy's planned grid improvements. This section includes (1) the estimated change in reliability measures, including normal-service reliability and major events and (2) the estimated net impact on business and household costs.

Duke Energy estimates that the Power/Forward grid improvements could reduce the number and duration of interruptions during normal service for the average customer by 40-60%, relative to the projected reliability without investment. The changes in these reliability metrics were then translated into the benefits of improved reliability for businesses and households:

- **Business benefits** are measured as a reduction in business operating costs (e.g. shutdown and restart costs, spoilage and damage, health and safety effects) as a result of reliability improvements (with investment vs. baseline with no investment).
- **Household benefits** are measured as a reduction in household costs (e.g. spoilage, property damage, health and safety effects) resulting from reliability improvements.[8]

These benefits are partially offset by the necessary increase in electricity prices to support the investment. Costs for businesses and households are the estimated increased electricity rates, based on projections provided by Duke Energy.

[8] Customer cost changes were estimated using information from Duke Energy's records and energy consumption data from the US Department of Energy Interruption Cost Estimation (ICE) tool. The ICE tool was used to estimate the overall business cost savings across all industries, including specific estimates for construction companies and manufacturers. The estimated impact across the remaining sectors was allocated to each industry (at the 2-digit NAICS level) based on historical energy intensity. Energy intensity was measured as the distribution of electricity absorption across industries based on the 2015 IMPLAN input-output economic model of North Carolina. Additional information is included in the appendix.

3.1 Change in normal-service reliability

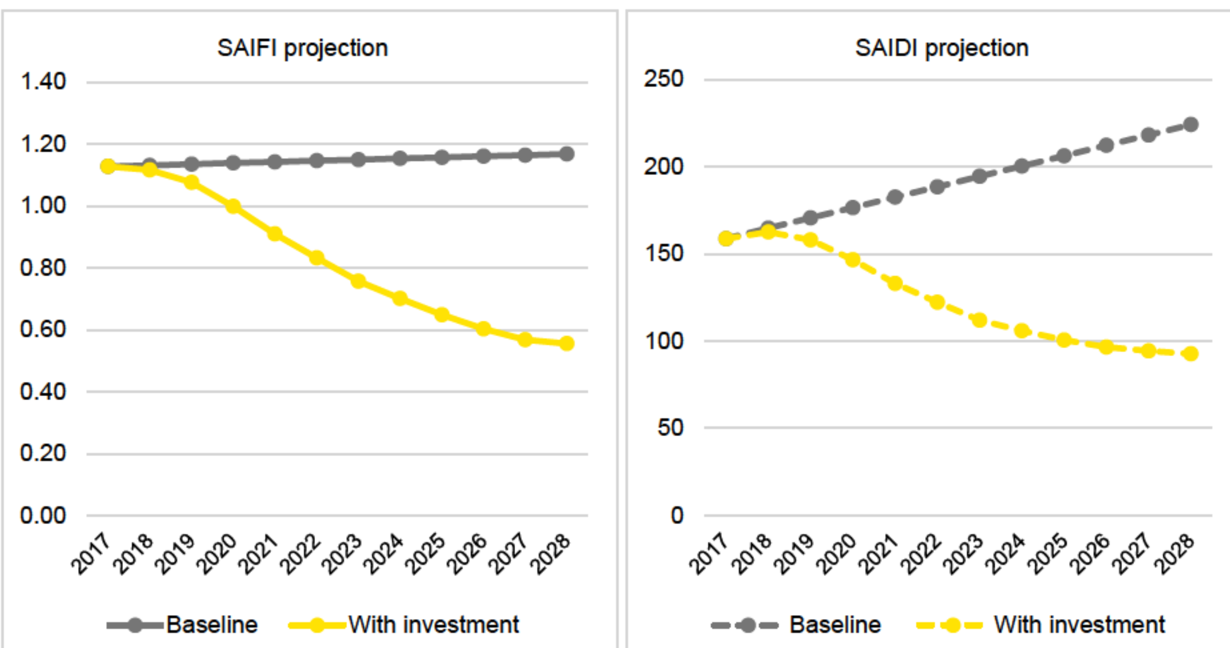
At current levels, Duke Energy's 3.2 million retail customers in North Carolina experience an estimated $1.17 billion in outage costs annually related to normal-service interruptions (non-major events). Businesses make up nearly all of this impact (98%).The annual cost is projected to grow to $1.70 billion without investment due to a projected decline in reliability using current infrastructure. With investment, these costs fall to $700 million. This approximately $1 billion reduction in outage-related costs is a benefit to businesses and households of improved electric reliability.

Electricity reliability is measured using two standard metrics:

- **System Average Interruption Frequency Index (SAIFI):** Total number of sustained (>5 minutes) customer interruptions / Total number of customers served
- **System Average Interruption Duration Index (SAIDI):** Total customer interruption duration (minutes) / Total number of customers served

Duke Energy estimates that Power/Forward could result in a 52% decrease in interruptions for the average North Carolina customer and a 59% reduction in the average outage time per customer, relative to projected reliability without investment (see Figures 3 and 4).

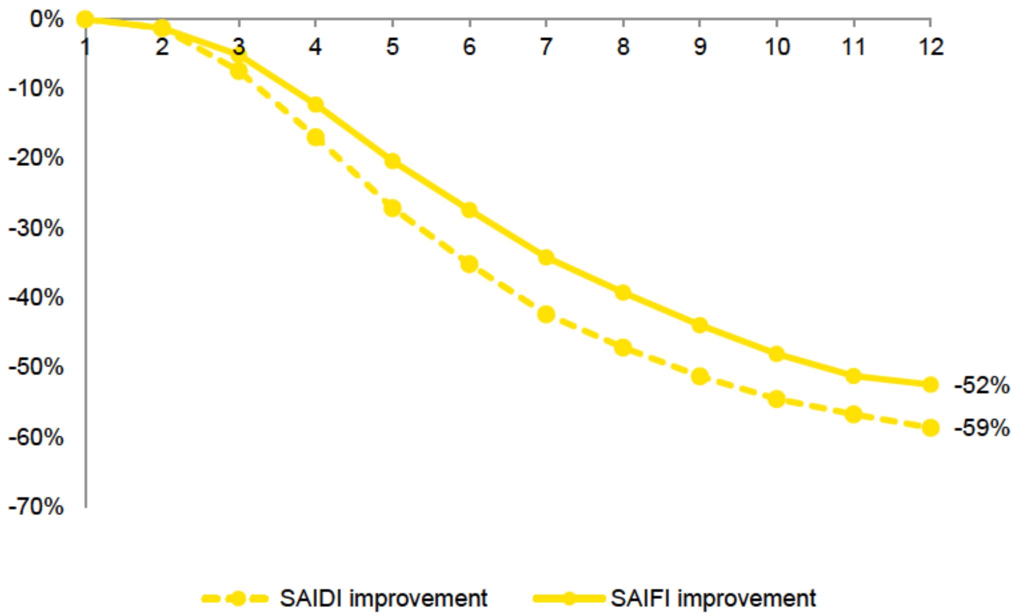
Figure 3. SAIFI and SAIDI projections, 2017-2028
Combined improvement from grid hardening, targeted undergrounding, and self-optimizing grid



Note: Excluding major events; Source: Duke Energy management.

Figure 4. SAIFI and SAIDI improvement compared to projected baseline, 2017-2028

Combined improvement from grid hardening, targeted undergrounding, and self-optimizing grid



Note: Excluding major events; Source: Duke Energy management.

3.2 Estimated average annual impact on major event days (MEDs)

The SAIFI and SAIDI projections in Section 3.1 do not consider the potential benefits related to avoided or shortened outages during major events. Clearly hurricanes, such as Matthew in 2016, are included in the impacts of major events, but there are many smaller scale multi-day events such as ice, severe thunderstorm, and wind storms that are also included in the calculation of Major Event Days (MEDs). For example, in 2016, Duke Energy customers that experienced an MED outage event(s) in North Carolina were out an average of 11.5 hours related to MEDs.

Duke Energy projects that Power/Forward grid improvements could, on average, reduce MED interruption time by 30%.

While MEDs are less common, the impacts to customers, businesses and communities are more severe. The benefit to businesses and household of reduced MEDs was estimated using the 10-year historical actuals to define an annual average customers interrupted (CI) and customer minutes interrupted (CMI) from major events. Duke Energy applied this annual average experience to project estimates of the avoided CI and CMI reductions that would be realized as a result of proposed Power/Forward grid investments. EY used this information as inputs into the ICE tool to estimate the direct static value of reliability improvements as the improved infrastructure comes online over the investment period. See Table 4.

Table 4. Estimated MED impacts, upon project completion

	Customers interrupted	Customer minutes interrupted
10-year historical average, NC	1,173,481	815,452,734
Estimated reduction (%)	33%	30%
Hypothetical MED, after project completion	789,797	567,233,923

Source: Duke Energy management.

This method only partially captures the value from the most severe events like Hurricanes Fran, Floyd, and Matthew as well as severe winter icing events like the December 2002 Ice Storm. Currently available models do not effectively capture the community impacts from these most severe events where widespread infrastructure damage may mean limited access to fuel, food, and shelter. In many cases (particularly in rural areas) these critical services are directly tied to electric infrastructure outages. An effective example to illustrate these broader benefits comes from looking at a specific analysis applied to Hurricane Matthew events and projects outcomes had proposed grid investments already been completed.

Table 5 shows a projected outage events reduction of 34% and a 30% reduction in duration from Matthew for the more heavily impacted DEP jurisdiction, with the potential to move Hurricane Matthew restoration completion from 6 days to nearly 4 days (excluding areas where flood waters prevented access). As well, DEC impacted areas were through the second day of restoration before being available to assist DEP. The 57% reduction in customers interrupted and the 45% reduction in CMI for DEC impacts from Matthew could enable those resources to be available to assist DEP a full day earlier.

Table 5. Hypothetical impacts of the project on Hurricane Matthew outages

	% Potential CI Eliminated	% Potential CMI Eliminated	% Potential Outages Eliminated
DEP NC	30%	30%	34%
DEC NC	57%	45%	32%

Source: Duke Energy management.

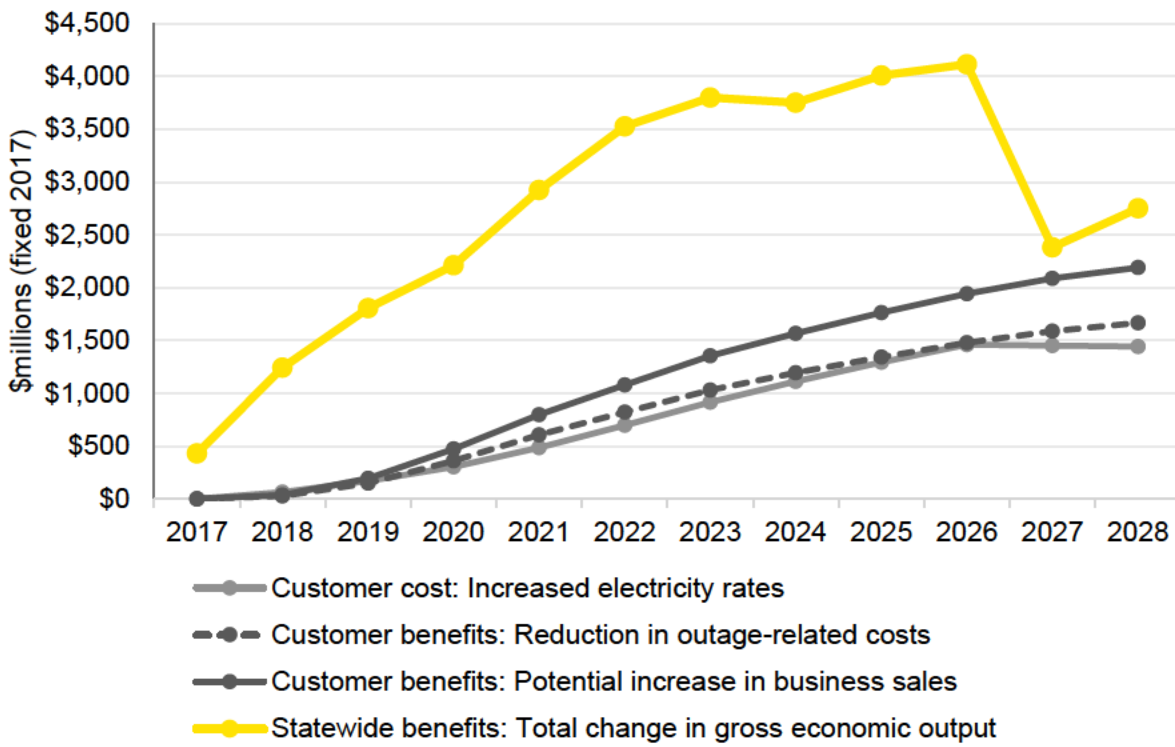
3.3 Net change in customer outage costs and electric rates

The business and household benefits grow over the investment period as Duke Energy's new infrastructure comes online. The anticipated benefit of the reliability improvement (in terms of avoided outage-related business costs) will range from $29 million in 2018 to $1.67 billion by the end of 2028, including $1 billion related to normal-service reliability and $670 million related to avoided MED outages. If these avoided costs were translated into related sales by businesses, the sales would total $2.20 billion by 2028.

These benefits will be partially offset by increased electricity rates paid by Duke Energy's customers to support the program investment. Duke Energy estimates that average retail electricity rates for North Carolina customers will increase by approximately 20% by 2026, relative to current rates. The rate increases grow along with investment and track with benefits over the period. The annual costs (incremental rate increases) will range from $62 million in 2018 to $1.44 billion by 2028.

The avoided outage costs and project investments will generate $32.93 billion in increased businesses sales (economic output). Theses statewide economic benefits are shown in Figure 5. On average, the project will generate $2.75 billion of economic output during each year of the project period, relative to the baseline state economic forecast.

Figure 5. Customer costs and benefits compared to statewide output impacts
Millions of 2017 dollars



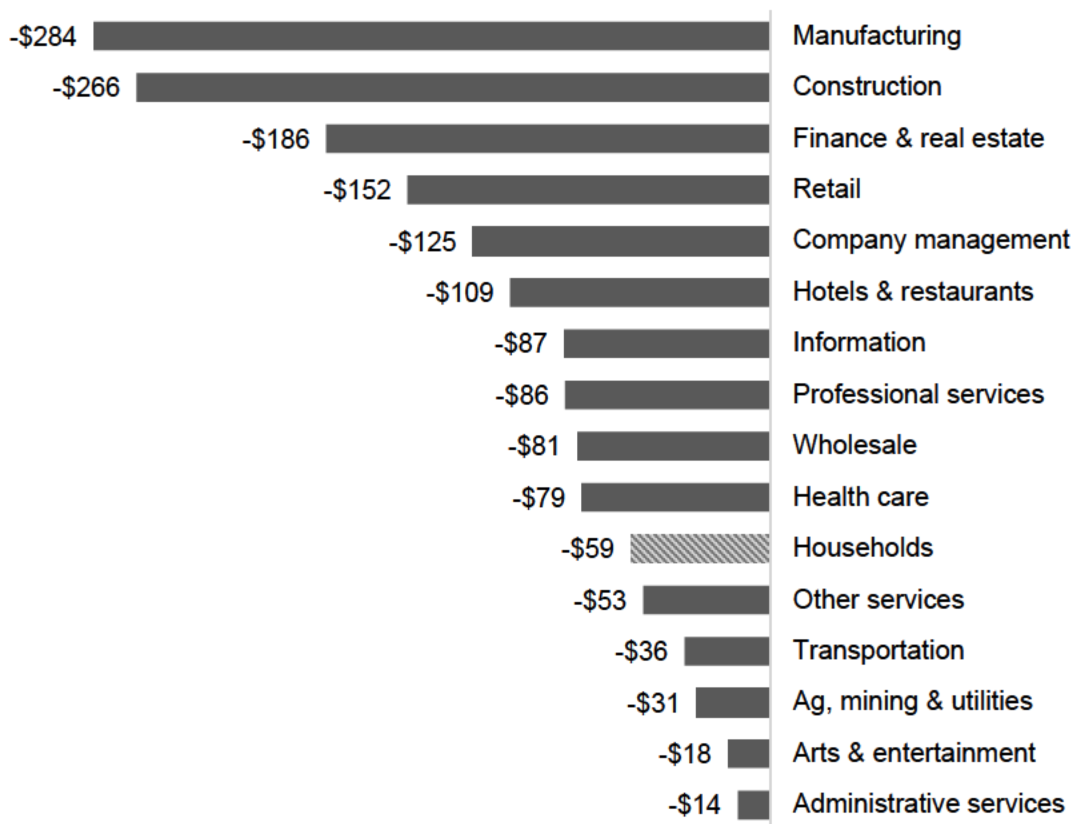
Note: Includes benefits related to normal-service and MED reliability improvements.
Source: Duke Energy management; EY analysis.

The benefits are driven by business production cost savings. According to estimates developed by the Berkeley National Laboratories for the Department of Energy (as used in the ICE tool), businesses incur a much higher cost of electricity outages than households. Manufacturers will realize 17% of the total benefit – totaling $284 million upon project completion. The remaining impact will be spread across all sectors of the economy, including households. See Figure 6.

EY estimates that industries will realize these cost saving benefits in proportion to their average electricity intensity. As shown in Figure 6, businesses in construction and manufacturing will realize the largest benefits (based on the econometric estimates underlying the ICE calculation tool). Finance and real estate will have the third largest overall benefit – primarily due to managed office buildings. The analysis estimates the average commercial & industrial (C&I) customer will receive a cumulative benefit of approximately $20,000 as a result of reliability improvements and avoided MEDs over the period (cumulative, 2018-2028).

Figure 6. Potential cost savings from reliability benefits, by sector

Annual cost savings, once fully-phased in (2028); Millions of 2017 dollars



Note: Includes cost savings related to both normal-service improvements and major event days.
Source: EY estimates based on data provided by Duke Energy; the DOE ICE tool; and the REMI economic model of North Carolina.

4. Economy-wide dynamic impact of infrastructure improvements

The economic impacts of reliability improvements will extend beyond the direct business cost reductions experienced by customers. EY estimated the dynamic economic impacts throughout the North Carolina economy using the REMI econometric model of the state.

The REMI model estimates the macroeconomic impacts of these changes in direct business and household costs into changes in statewide employment, GDP, resident income, and state and local taxes supported through purchases of intermediate goods, spending by households, and investment activity. These impacts are summarized in Table 6. As businesses realize the benefits of these cost reductions, they will support additional economic activity through incremental purchases of operating inputs and payments to employees. This activity will support up to an estimated 15,256 jobs after implementation (in 2028), including indirect and induced economic activity.

The impacts will phase in over several years as the economy adjusts. Although Figure 7 shows continuous employment growth, the incremental economic impacts related to the project (relative to the baseline) will decline over time, as the economy adjusts after the completion of the project. This analysis presents impacts over three periods: (1) mid-investment (investment year 5, 2022), (2) end of investment period (year 11, 2028), and (3) investment period total (11-year cumulative impacts).

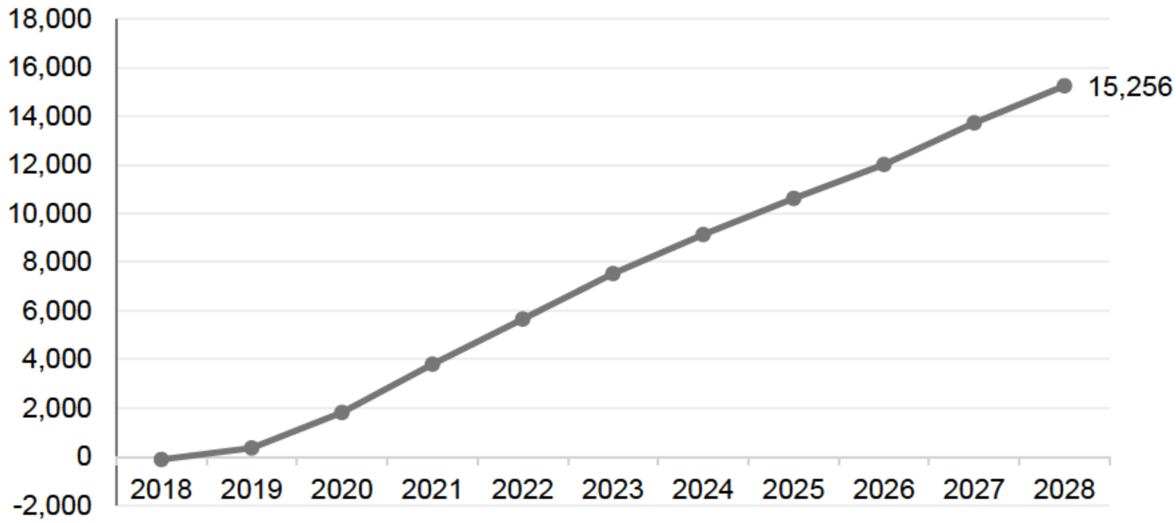
This economic activity will drive a cumulative impact of $421 million in tax revenues for state and local governments over the 11-year period. This includes $276 million of estimated state taxes paid by businesses and households. The annual tax impact will reach $89 million by the end of the investment period (2028).

Table 6. Estimated economic impacts of reliability increases, total impact
Millions of 2017 dollars

	Year 5 2022	Year 11 2028	Cumulative 11-yr. total
Employment	5,658	15,256	7,259*
Economic output	$806	$2,750	$12,905
GDP	$407	$1,434	$6,602
Labor income	$313	$981	$4,806
Private investment	$131	$431	$1,934
State taxes	$17	$59	$276
Local taxes	$9	$31	$145

*Average jobs in place in each year.
Source: Duke Energy management; EY analysis.

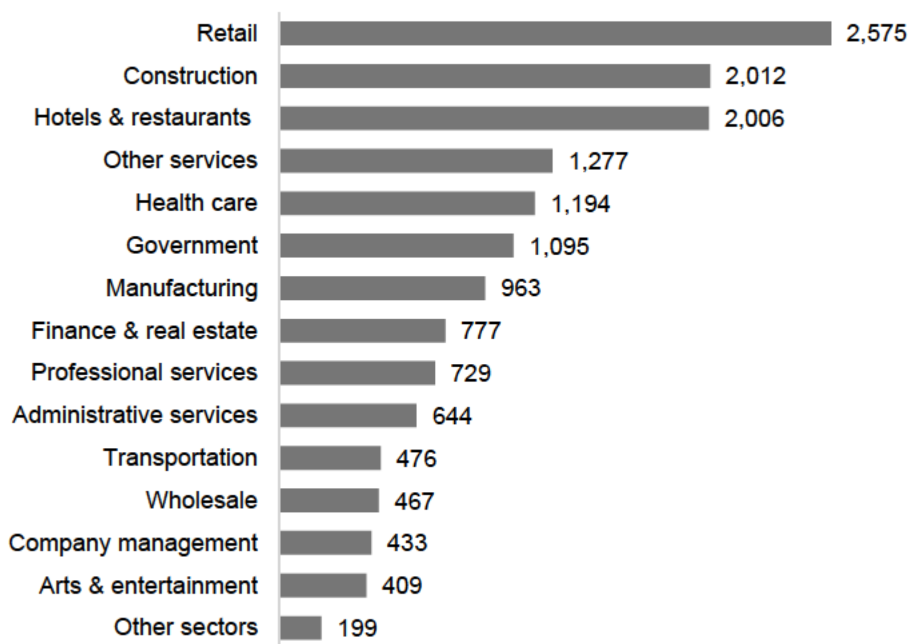
Figure 7. Estimated employment impact of reliability increases, by year



Source: EY analysis based on the REMI economic model of North Carolina.

The largest employment impacts will be in the retail sector, related to employee household demand. The construction sector will also see a significant employment impact, as result of additional investment related to the increased economic activity. See Figure 8.

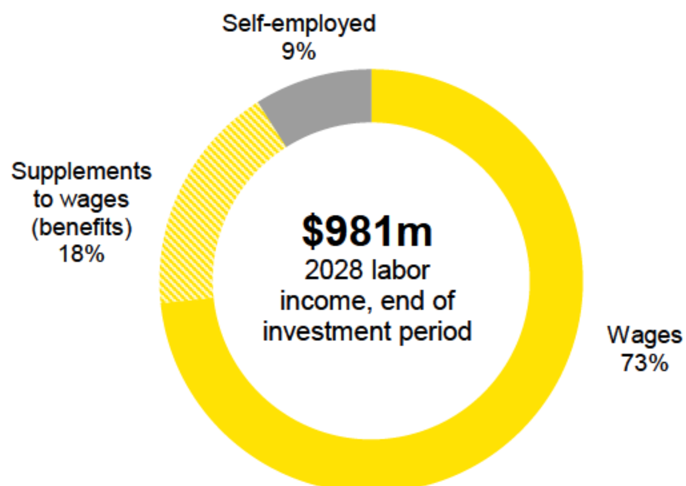
Figure 8. Employment impacts of reliability increases, by sector
2028, end of investment period



Source: EY analysis based on the REMI economic model of North Carolina.

Figures 9 and 10 illustrate the composition of the labor income and GDP impacts. Figure 9 shows that the projected increase in statewide labor income resulting from increased employment and economic activity includes cash wages earned by employees, benefits and other non-cash payments provided to employees as part of their total compensation, and earnings of self-employed workers including independent contractors. Reliability improvements will result in an estimated increase of $4.81 billion in income earned in North Carolina over the 11-year period, totaling $981 million in 2028. Wages and benefits earned by employees account for approximately 90% of this amount. These workers will earn an average of $70,000 in total compensation, including estimated wages, overtime, and benefits.[9] See Figure 9.

Figure 9. Components of total labor income from reliability increases, 2028
2017 dollars

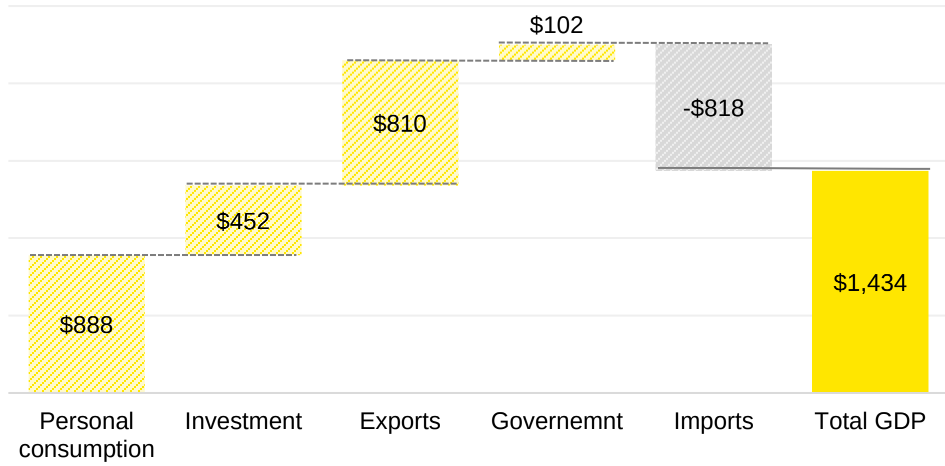


Source: EY analysis based on the REMI economic model of North Carolina.

The avoided outage costs will generate an estimated nearly $6.60 billion boost to state GDP over 11 years, generated as a result of $12.91 billion in increased businesses sales (economic output). The GDP impact is driven by personal consumption and investment activity. See Figure 10, which shows the composition of GDP, by final demand use. The change in personal consumption spending accounts for the largest share of GDP, while investment accounts for the second largest positive contribution. The higher level of income and economic activity also increases statewide imports, which is netted against other items to yield the overall $1.43 billion GDP impact in 2028.

[9] Employment represents the total number of full- and part-time employees and includes sole proprietors.

Figure 10. Components of GDP impact from reliability increases, 2028
Millions of 2017 dollars



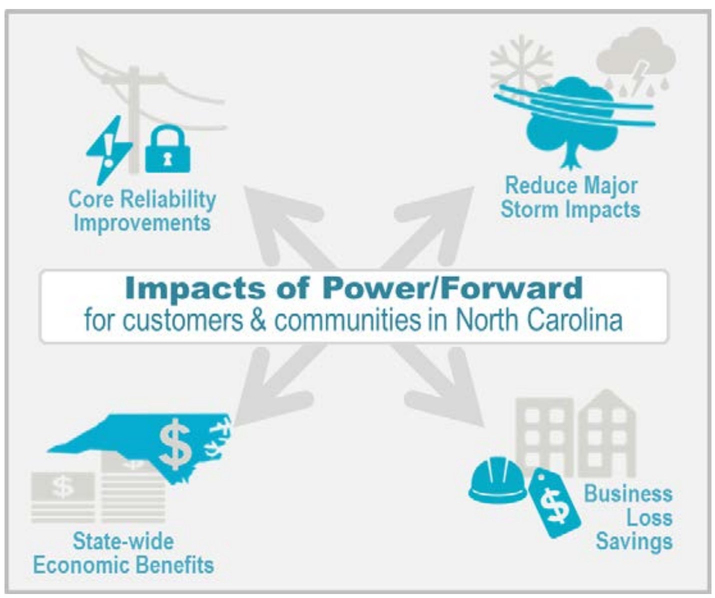
Source: EY analysis based on the REMI economic model of North Carolina.

Part 3: Conclusions – Statewide impacts of Duke Energy's Power/Forward program

As shown in this report, Duke Energy's North Carolina Power/Forward program has the potential to provide benefits in four ways.

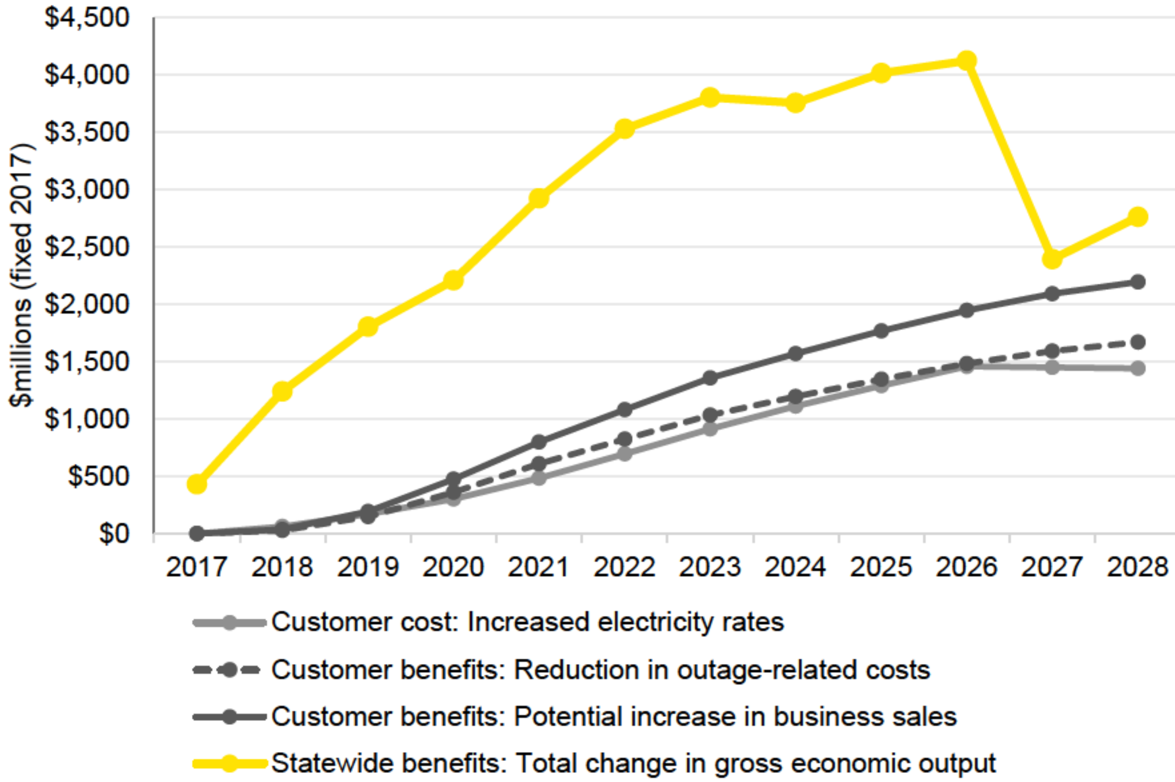
1. **Improved non-major event reliability.** The Power/Forward investments in the grid will improve reliability for Duke Energy customers during normal operations by approximately 40-60%. For both businesses and households, this means the frequency of power outages and the duration of those outages will decrease.
2. **Improved major event reliability.** As a result of the investment, Duke Energy customers will enjoy an estimated 30% fewer minutes of total outages during major events, including storms and hurricanes. These reduced outages will provide benefits to customers such as reduced food spoilage for households and reduced interruption costs for businesses. In addition, by preserving or more quickly restoring power to customers during major events, the entire state can more quickly resume normal functioning after a major event.
3. **Reduced outage-related business costs.** Reduced business costs resulting from a more reliable electric grid make North Carolina a more competitive place to do business. By 2028, the analysis shows that North Carolina businesses will save $1.7 billion per year from reduced outage-related costs. Businesses with more reliable access to electricity operate more efficiently and make North Carolina's business environment more competitive.
4. **Economic benefits.** The economic benefits arise from a more reliable electric grid and more competitive business environment as well as the jobs and spending supported by the grid investment itself. While customer rates will increase as a result of the capital spending, the economic benefits are estimated to exceed these costs. In total, our analysis shows that 19,000 jobs will be supported statewide through higher levels of economic activity associated with improved reliability and the spending associated with the plan.

The "four corners" of Duke Energy's Power/Forward program



Source: Duke Energy management.

Figure 11. Business and household benefits and costs
Millions of 2017 dollars



Note: Includes benefits related to normal-service and MED reliability improvements
Source: Duke Energy management; EY analysis.

5. Appendix: Study methodology

5.1 Estimating the temporary impacts related to capital expenditures

The estimated economic and tax contributions presented in this study are based on information regarding Duke Energy's proposed capital investments in system-wide upgrades and improvements over the next ten years, provided the client's management. The state and local economic and tax impacts related to this activity were estimated using the statewide Economic Impact Analysis for Planning (IMPLAN) input-output economic model for North Carolina, which describes relationships between businesses, households, and governments within the state. This model follows economic flows, as purchases of local goods by companies and employees support sales, jobs, and tax revenues. IMPLAN is used by the public sector as well as private-sector businesses and other researchers and is based on widely accepted methodology for estimating these types of economic linkages.

The magnitude of each economic effect is described in terms of an economic multiplier. The multipliers in the IMPLAN model are based on the Leontief matrix, which estimates the total economic requirements for every unit of direct output in a given industry using detailed inter-industry relationships documented in the input-output model. The input-output framework connects commodity supply from one industry to commodity demand by another. The multipliers estimated using this approach capture all of the upstream economic activity (or backward linkages) related to an industry's production by attaching technical coefficients to expenditures. These output coefficients (dollars of demand) are then translated into dollars of GDP and labor income and number of employees based on industry averages.

In general, estimated tax impacts are estimated based on the historical relationship between state and local tax collections (by tax type) to economic activity (measured as personal income). This ratio estimates the effective tax rates for each tax type as a share of total personal income. This approach assumes that Duke Energy employees and taxes from the indirect and induced activity will generate taxes at the statewide and countywide average effective rate on economic activity.

Limitations

The reader should be aware of the following model limitations and assumptions when interpreting the capital investment impact results:

- Indirect economic impacts were estimated based on relationships in the IMPLAN input-output model, which describe the mix of locally supplied goods and services, by industry, based on historical purchasing relationships. The IMPLAN industry models were chosen to most closely resemble the mix of activities related to the planned capital expenditures and incremental maintenance costs, but may be different in some cases.

- In general, indirect and induced tax impacts are estimated based on state averages for all industries and households. These estimates do not incorporate industry-specific tax rates, exemptions, or bases.

- The economic impacts presented in this report quantify the economic activity supported by Duke Energy's investments and purchases. In some cases, the indirect and induced jobs not be net new to the state, but are temporarily supported by Duke Energy's expenditures.

Direct state and local sales and use taxes on construction materials were estimated based on the applicable statutory tax rates (4.75% state; 2.25% average local rate), assuming 49% of construction expenditures are on taxable materials for the capital investment and 25% of incremental operations and maintenance costs are on taxable materials.

5.2 Estimating the direct impact on business costs

To estimate the direct economic impacts of increased reliability that could result from Duke Energy's infrastructure investments in North Carolina, this analysis used data from Duke Energy as inputs to the US Department of Energy's Interruption Cost Estimate (ICE) Calculator[10], which uses an econometric model to estimate the cost to businesses and households of interruptions in electrical supply. EY then allocated the cost estimates from the ICE Calculator to industry sectors at the 2-digit NAICS level based on each sector's consumption of electricity as indicated by the intermediate use table in the 2015 IMPLAN input-output economic model of North Carolina.

The ICE Calculator was developed by Nexant and the Lawrence Berkeley National Laboratory for the US Department of Energy for use by utilities and governments in understanding the economic impact of electrical grid reliability. It is based on an econometric model developed using data "from 28 customer value of service reliability studies conducted by 10 major U.S. electric utilities over the 16-year period from 1989 to 2005."[11] The underlying econometric model estimates the interruption cost for three types of customers: (1) medium and large commercial and industrial customers (C&I) defined as customers using more than 50,000 kWhs annually, (2) small C&Is defined as those using less than 50,000 kWhs annually, and (3) residential customers. For each type of C&I, interruption cost was estimated with a regression model as a function of the duration of the outage, the industry affected, and other seasonal/temporal factors. A similar approach was used for residential customers taking into account duration of the outage, demographic characteristics of the households, and temporal factors.

The primary limitations of the ICE Calculator stem from the data used to fit the underlying model. In particular, about 50% of the data available was more than 15 years old as of 2015, no data was available for the northeast or Mid-Atlantic, there was limited data available for the Great Lakes region, and the data does not include outages with duration greater than 24 hours. Another set of limitations arise from how the data was collected. Because the data was originally collected by utility companies for planning purposes, "interruption conditions described in the surveys for a given region tended to focus on periods of time when interruptions were more problematic for that region."[12] In addition, because different surveys were done at different times, there is significant multicollinearity in the data e.g. between survey year and region. Finally, the ICE Calculator is

[10] *Interruption Cost Estimate Calculator*.
[11] Michael J. Sullivan, Josh Schellenberg, and Marshall Blundell, "Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States."
[12] Ibid.

limited by its level of industry detail. The study that the ICE Calculator is based on estimates interruption impact coefficients for three broad industries: manufacturing, construction, and all other. The ICE Calculator then by default takes as an input only an aggregate number of C&Is and allocates these between sectors based on Census establishment counts.

Duke Energy provided North Carolina customer accounts by category and outage data from which EY estimated the current reliability measures (SAIFI and SIDI). These measures were estimated excluding Major Event Days (MEDs). EY then used counts of customer accounts by type and the reliability measures as inputs to the ICE Calculator, which yielded estimates of the direct economic value of reliability improvements for the construction, manufacturing, and other sectors. To refine these estimates, EY used the IMPLAN 2015 North Carolina use table to allocate the ICE Calculator's other impacts across 2-digit NAICS sectors based on each sectors' use of electricity as an input to production. In addition, a portion of the impacts related to real estate rental and services were allocated to the industries that employ those services to more accurately reflect the industries that benefit from increased electrical grid reliability.

EY accepted the default ICE settings for:

- Percentage of accounts in construction, manufacturing, and all other industries,
- Percentage of customers with backup generation and/or power conditioning equipment,
- Distribution of outages by time of day, and
- Distribution of outages by time of year.

These default settings were based on historical data for North Carolina.

5.3 Estimating the total economic impacts

This analysis estimates the indirect economic impact of improving electricity generation and distribution infrastructure in North Carolina through use of a Computable General Equilibrium (CGE) model of the state economy. In particular, the estimated direct business operating cost savings resulting from increased reliability is used as an input to a CGE economic model, developed by Regional Economic Models, Inc. ("REMI") and used under license by EY. The CGE model incorporates input-output, general equilibrium, econometric, and economic geography methodologies to estimate impacts on macroeconomic variables and estimate industry-specific results for the North Carolina economy. The REMI model estimates the reduction in business costs will impact:

- **Intermediate demand for inputs (indirect effects):** Resulting from additional purchases from suppliers to produce final goods.

- **Local consumption demand (induced effects):** Resulting from the increase in personal income and subsequent household spending.

- **Investment activity:** Demand for capital goods

- **Exports & imports:** Trade within the US and with other countries

- **Government activity:** Resulting from additional government expenditures

The input-output module of the model takes into account the inter-industry transactions within the state economy as well as the economy's interaction with buyers and sellers in other parts of the United States as well as other countries. The social accounting matrix contained in the CGE model extends this model of inter-industry dependence to transactions between industries, households, and government. In this way, the CGE model estimates economic impacts that consider the same types of direct, supplier-related, and consumption-related impacts that are estimated by users of an input-output model.

Additional features of the CGE model include:

- **Consideration of supply-side constraints.** The CGE model takes into account supply-side constraints on the economy. That is, the extra output cannot be produced in one area without taking resources away from other activities.
- **Change in prices with variation in supply and demand.** Constraints on the availability of inputs, such as skilled labor and intermediate goods, require prices to act as a rationing device. A CGE model allows prices to vary and capture the supply and demand of industry inputs.
- **Change in consumption shares.** The REMI model allows for the household budget share of goods and services to vary depending on relative prices.
- **Adjustment dynamics of market economy.** CGE models mimic the economy's adjustment process from one equilibrium to another after an economic shock. As such, the model does not provide a timeless impact, but annual changes incorporating the time path of the change in operations and the behavioural changes of businesses and consumers.

The parameters used to define structural relationships in the model are quantified through an econometric methodology. These elasticity estimates allow the behavioral sensitivity of businesses and consumers to changes in the price of goods and services to vary by industry. Examples of econometrically determined response parameters include income and price elasticities of demand for various goods, factor substitution elasticities, and export transformation elasticities. This reflects that consumers, in the example of good-specific price elasticities of demand, will be more responsive to a change in the price of some goods (e.g., luxury goods) than others (e.g., necessities).

A REMI model was selected based on its recognized credibility for simulating economic impacts. REMI models are widely used by universities, government agencies, and private research organizations, including most US state governments. Academic journal articles regarding the model equations and simulation results have been published in the American Economic Review, the Review of Economic Statistics, the Journal of Regional Science, and the International Regional Science Review.

Limitations

The reader should be aware of the following model limitations and assumptions when interpreting the reliability impact results:

- Estimates of the direct business cost reduction are based on the Department of Energy Interruption Cost Estimator (ICE) tool developed by Nexant and Lawrence Berkeley National Laboratory. While this tool is believed to contain correct information, EY does not assume any legal responsibility for the accuracy or completeness of the information.
- State and local tax impacts are estimated based on statewide averages for all industries and households. These estimates do not incorporate industry-specific tax rates, exemptions, or bases.

6. References

Alan H. Sanstad, Ph.D. “Regional Economic Modeling of Electricity Supply Disruptions: A Review and Recommendations for Research.” Berkeley Lab, March 2016.

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BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-9

Duke Energy Carolinas Response to
Second Data Request of NCSEA
Data Request No. 2-15

Docket No. E-7, Sub 1146

Date of Request: **January 3, 2018**
Date of Response: **January 11, 2018**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 2-15, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 2-15

Request:

On Page 41 of his testimony, Witness Simpson testifies that "The dynamic demands on our system such as the penetration of renewables is already exposing the limits of the legacy grid."

Please identify the investments, including cost that DEC plans to make as a part of its grid modernization plan that would allow the grid to better accommodate renewable energy generation.

Response:

While not specifically intended to accommodate renewables, Power/Forward investments such as AMI, Self-Optimizing Grid and Advanced Enterprise Systems will allow the grid to better accommodate renewable energy generation. The 10-year capital portion of these three programs for DEC is estimated at:

AMI = $256M
Self-Optimizing Grid = $781M
Advanced Enterprise Systems $207M

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-10

Duke Energy Carolinas Response to
Second Data Request of NCSEA
Data Request No. 2-9

Docket No. E-7, Sub 1146

Date of Request: January 3, 2018
Date of Response: January 12, 2018

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The attached response to NCSEA Data Request No. 2-9, 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.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 2-9

Request:

On Page 23 of his testimony, Witness Simpson testifies how DEC plans for capital and O&M expenditures over and above its "customary level of spend".

(a) Please describe in detail what the "customary level of spend" is for DEC over the next five years is projected to be.
(b) Please identify how much DEC investment above the customary level of spend is planned to be made in DEC's North Carolina service territory and in DEC's South Carolina service territory.
(c) Please identify the investments that DEC plans to make in its North Carolina service territory, including a breakdown of the improvements that are planned and the costs associated with each improvement.
(d) Please provide copies of all documents prepared related to the investment projected over the next five years' time above the customary level of spend for DEC. These documents should include, but are not limited to, minutes, presentations, and reports to Senior Management, to the Board of Directors, and to Board Committees.

Response:

a) The types of investments included in the customary spend are the same types of expenditures depicted in the Transmission and Distribution Capital Expenditures pie charts shown on page 9 and 11 of Witness Simpson testimony.

b) The amount above the customary level of spend would be the planned Power Forward Investments in NC and SC over the 2017-2021 timeframe. Those amounts are $2.9B in NC and $629K in SC. Both amounts exclude AMI project which is already underway. The amounts with AMI are $3.2B in NC and $695K in SC.

c) The details of the $2.9B DEC-NC Power Forward spend are provided in item 8 of this data request.

d) Please see the attachments provided in response to NCSEA 4-2.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-11

Duke Energy Carolinas Response to
First Data Request of the Environmental Defense Fund
Data Request No. 1-9

Docket No. E-7, Sub 1146

Date of Request: **December 7, 2017**
Date of Response: **December 22, 2017**

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The attached response to Environmental Defense Fund's ("EDF") Data Request No. 1-9, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to EDF under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

EDF 1-9

Request:

Refer to witness Simpson testimony, page 25, line 1, in which $2.9 billion in grid modernization investments are purported to "help integrate and manage intermittent distributed renewable resources and position the grid for emerging technologies such as battery storage . . . ". Distributed generation and storage are generally known by the term Distributed Energy Resources (DERs), and the capacity (in MW) of DERs which can be reliably accommodated on a circuit is generally known by the term "hosting capacity".

a. Please describe the components of the Company's proposed $2.9 billion in modernization investments which will serve to increase DER hosting capacity.

b. Please estimate the DER hosting capacity (in MW) of the Company's grid today, prior to the addition of such components.

c. Please estimate the percent increase in DER hosting capacity these components of the modernization investment plan will enable. Include in your response all workpapers, worksheets, calculations, estimates, assumptions, and other materials used to calculate these estimates.

Response:

a. Several Power/Forward investments such as AMI and Self-Optimizing Grid and Advanced Enterprise Systems will help the Company to integrate and manage intermittent distributed renewable resources and position the grid for emerging technologies such as battery storage. Portions of the investments will involve upgrading distribution circuits with larger conductors, as part of reliability enhancement efforts. A corollary benefit of conductor upgrading is "system stiffening;" i.e., reducing system impedance from points on the distribution circuit back towards the transmission system. This provides a stronger connection to the transmission system and therefore a larger "pipe" to allow DERs to operate independently of load patterns and flow their full output back towards the transmission system.

b. The Company does not currently calculate, nor can it estimate, the DER hosting capacity of individual circuits or the grid as a whole. There are several reasons: (1) There is no industry standard that sufficiently defines this term, (2) the calculation for most any definition of this term would be exceedingly complex, and (3) there is no benefit to customers to such an estimation or calculation. The Company studies and accommodates interconnections as part of its obligations under the North Carolina Interconnection Standards.

c. This has not been and cannot be estimated nor calculated, for reasons stated above.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-12

Duke Energy Carolinas Response to
Tenth Data Request of NCSEA
Data Request No. 10-9

Docket No. E-7, Sub 1146

Date of Request:	**January 5, 2018**
Date of Response:	**January 14, 2018**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 10-9, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 10-9

Request:

Please refer to the spreadsheet responsive to NCSEA Data Request No. 8-7 and entitled "NCSEA 8-7 DEC NC TUG Request.xlsx".

Column W in this spreadsheet labeled Events/Target Miles (10 years) has values ranging from 12 to 5,514.

(a) Please confirm that the Company used the values in Column W to rank/prioritize circuit segments for the TUG program. If not, please clarify.
(b) Please provide all data, analysis, studies, reports, or other evidence explaining how the Company determined that 12 events/target miles is the minimum value for a circuit segment to be included in the TUG program.

Response:

a. Yes, the Company uses the values in Column W to rank or prioritize circuit segments for the TUG program generally. However, for the first year of the program in 2018, we are prioritizing targets from that list that are simpler in planning and coordination time so that construction could be initiated and completed within the 2018 calendar year.

b. Duke Energy's policy regarding proposed TUG candidate targets is to review sites where the distribution overhead infrastructure is at least 50% worse than the average overall overhead performance in faults per mile. Duke Energy will limit the TUG candidate sites to not more than 20% of total vegetated overhead line miles, although that limit was not a factor for DEC NC.

DEC NC's distribution overhead averages 0.81 faults per mile. The 12 events per mile for a target segment the question references is the ten year total, which translates to an annual average of 1.2 faults per mile. Therefore, the target segments perform at least 50% worse than the overall OH average for DEC NC of 0.81 faults/mile. These segments for DEC NC also range from 6 to 100 times worse than the better performing portions of backbone overhead and the overall performance for underground (both average around 0.2 faults/mile). This extended and consistent pattern of outlier performance is why these segments are candidates for the TUG program.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina	**)** **)** **)** **)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-13

Duke Energy Carolinas Response to
Fourth Data Request of NCSEA
Data Request No. 4-4

Docket No. E-7, Sub 1146

Date of Request:	**December 20, 2017**
Date of Response:	**January 3, 2018**

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The attached response to NCSEA Data Request No. 4-4, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

Heather Smith
Deputy General Counsel
Duke Energy Carolinas

NCSEA 4-4

Request:

Is the Company currently studying or investigating the ability of customer-owned distributed energy resource assets, including "smart inverters" and energy storage devices, to be programmed to provide ancillary services (e.g., voltage support, frequency regulation, among other things) to the Company's system as a functional substitute to specific projects within the grid modernization plan?

If such customer-owned devices could be utilized by the Company (through new programs to enlist those systems to be subject to utility dispatch and control), does the Company agree that such programs could be considered as a lower-cost alternative to a specific project within the grid modernization plan? If not, please explain why utility ownership of assets providing grid modernization functions is a necessity.

Response:

No, the Power Forward program is focused on the distribution and transmission infrastructure to improve the overall reliability and resiliency of the grid, but increased grid capacity will aid in interconnecting distributed generation.

The Company continues to evaluate the system cost and benefits of distributed generation, including the provision of ancillary services, but doesn't anticipate that DG deployment will impact measures currently under consideration as part of the Power Forward program.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION
DOCKET NO. E-7, SUB 1146

In the Matter of:	**)**
Application of Duke Energy Carolinas,	**)**
LLC for Adjustment of Rates and	**)**
Charges Applicable to Electric Service	**)**
in North Carolina	**)**

DIRECT TESTIMONY OF
CAROLINE GOLIN
ON BEHALF OF
NORTH CAROLINA SUSTAINABLE ENERGY ASSOCIATION

EXHIBIT CG-14

Duke Energy Carolinas Response to
Second Data Request of NCSEA
Data Request No. 2-44

Docket No. E-7, Sub 1146

Date of Request: **January 3, 2018**
Date of Response: **January 11, 2018**

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X	**NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 2-44, was provided to me by the following individual(s): Evan W. Shearer, Smart Grid Planning Manager, Grid Solutions Regulatory Planning, and was provided to NCSEA under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

NCSEA 2-44

Request:

On Page 17 of his testimony, Witness Fountain testifies:

> DE Carolinas is continuing to expand and enhance its portfolio of demand side management ("DSM") and energy efficiency ("EE") programs because these programs have proven to be one of the most effective means to reduce energy costs, offset the need for new power plants, and protect the environment. DE Carolinas' robust portfolio of EE programs is designed to provide offerings that engage and educate customers around their energy usage and efficiency, as well as empower them with financial incentives and opportunities to invest in efficiency improvements and make informed energy saving choices. DE Carolinas offers customers more than a dozen energy saving programs for every type of energy user and budget. The Company's EE programs currently save its customers in the Carolinas over 4.3 billion kWh annually or more than $357 million, which is about 5.4 percent of total retail kWh sales. Combined, its DSM and EE programs offset capacity requirements by the equivalent of more than seven power plants. The Company's growing portfolio of DSM programs, which are designed to manage customer demand for electricity, further offer customers opportunities to lower their bills by providing them with financial incentives in exchange for shifting the timing of their electricity use from peak to non-peak periods, thereby helping DEC to reduce fuel costs during the periods when energy costs the most to produce.

Recognizing the benefit of DSM programs, were any DSM options explored as investment opportunities in the Power/Forward investments.

Response:

DSM options were not explored as Power/Forward initiative opportunities. The Company manages DSM programs through its existing DSM/EE planning processes, rather than through Power/Forward.