INFORMATION SHEET

PRESIDING: Chairman Finley, Presiding; and Commissioners Brown-Bland, Dockham, Patterson, Gray, Clodfelter, and Mitchell
PLACE: Dobbs Building, Room 2115, Raleigh, NC
DATE: Wednesday, January 30, 2019
TIME: 9:30 a.m. to 12:43 p.m.
DOCKET NO.: E-100, Sub 101; E-2, Sub 1159; E-7, Sub 1156
VOLUME NUMBER: 5
COMPANIES: Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
DESCRIPTION: Petition for Approval of Generator Interconnection Standard and Joint Petition of Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, for Approval of Competitive Procurement of Renewable Energy Program

APPEARANCES
Please see attached.

WITNESSES
Please see attached.

EXHIBITS
Please see attached.

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REPORTED BY: Joann Bunze
DATE FILED: February 13, 2019

TRANSCRIPT PAGES: 159
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TOTAL PAGES: 245

PLACE: Dobbs Building, Raleigh, North Carolina

DATE: Wednesday, January 30, 2019

TIME: 9:30 a.m. - 12:43 p.m.

DOCKET NO.: E-100, Sub 101

E-2, Sub 1159

E-7, Sub 1156



BEFORE: Chairman Edward S. Finley, Jr., Presiding

Commissioner ToNola D. Brown-Bland

Commissioner Jerry C. Dockham

Commissioner James G. Patterson

Commissioner Lyons Gray

Commissioner Daniel G. Clodfelter

Commissioner Charlotte A. Mitchell

IN THE MATTER OF:

Petition for Approval of Generator

Interconnection Standard

and

Joint Petition of Duke Energy Carolinas, LLC,

and Duke Energy Progress, LLC, for

Approval of Competitive Procurement of

Renewable Energy Program

Volume 5

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EXAMINATIONS

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**PROTESTANT** ___ **RESPONDENT** ___ **DEFENDANT** ___

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# NORTH CAROLINA UTILITIES COMMISSION

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DATE 1/28

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**PROTESTANT** ___ **RESPONDENT** ___ **DEFENDANT** ___

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**PROTESTANT** ___ **RESPONDENT** ___ **DEFENDANT** ___

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# NORTH CAROLINA UTILITIES COMMISSION
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**APPLICANT** ___ **COMPLAINANT** ___ **INTERVENOR** ✓

**PROTESTANT** ___ **RESPONDENT** ___ **DEFENDANT** ___

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**PROTESTANT** ____ **RESPONDENT** ____ **DEFENDANT** ____

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# NORTH CAROLINA UTILITIES COMMISSION
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# NORTH CAROLINA UTILITIES COMMISSION
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# NORTH CAROLINA UTILITIES COMMISSION
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**PROTESTANT** ____ **RESPONDENT** ____ **DEFENDANT** ____

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# NORTH CAROLINA UTILITIES COMMISSION
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**PROTESTANT** ____ **RESPONDENT** ____ **DEFENDANT** ____

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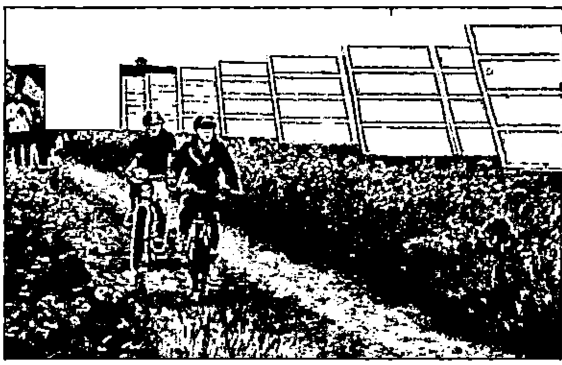
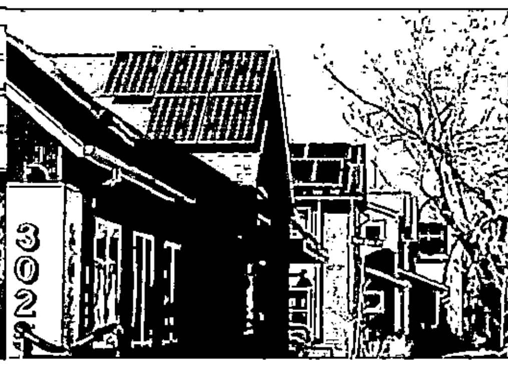





# Priority Considerations for INTERCONNECTION STANDARDS:

## A Quick Reference Guide for Utility Regulators

IREC
Interstate Renewable Energy Council

August 2017

# Priority Considerations for **INTERCONNECTION STANDARDS:**

## A Quick Reference Guide for Utility Regulators

The power grid is much like our network of country roads, highways and freeways, carrying energy from its origin to its final destination. Interconnection standards are, in effect, the "rules of the road," set by policymakers, which both system owners and utilities must follow to keep traffic flowing smoothly. The quality of these rules—like any given street sign, traffic direction or roadmap—can facilitate an easy free-flow of traffic, or result in unnecessary gridlock. As we introduce new technologies and services, the rules must evolve.

At a basic level, interconnection standards should outline with clarity the timelines, fees, technical requirements and steps in the review process for connecting distributed energy resources—such as a solar PV system or an energy storage system—to the electricity grid. Ideally, the process to interconnect should not be an obstacle or a source of frustration and contention for any party involved in the process. Clear, forward-thinking rules are essential to maintain the safety and reliability of the grid, while also enabling the adoption of distributed energy resources and achieving broader clean energy and resiliency goals.

As an active participant at the Federal Energy Regulatory Commission (FERC) and in dozens of state commission rulemakings over the past decade, the Interstate Renewable Energy Council (IREC) has identified and synthesized the best practices in use across the country in our *Model Interconnection Procedures*, which is a free resource available to states for reference as work to develop and/or refine their own rules. IREC's aim with these model procedures is to streamline the regulatory process, save states' resources, and avoid the need to reinvent the wheel on interconnection.

This document is intended to serve as a supplement to IREC's Model Rules and provides a list of key interconnection considerations for states working to improve/update interconnection procedures. Each section offers a description of the key components to interconnection based upon established and well-vetted national best practices. In each case, we provided links to the most relevant examples, though other examples do exist in most cases.

For more information and to download other resources, please visit our website at www.irecusa.org.

# Table of Contents

# I. Project Applicability and Review Processes for Interconnection Applications

## A. Applicability to All Projects

Some state procedures have been drafted so that they are applicable to projects only below a certain size threshold. This limitation means that some state jurisdictional projects may have no clear pathway to obtain an interconnection agreement since jurisdictional considerations, and not necessarily size, dictate whether a project must interconnect pursuant to state or federal interconnection procedures. This determination may correlate to some degree with size, since the state-jurisdictional distribution system uses lower voltage lines that can typically only accommodate projects up to a certain size (e.g., 20 MW). Nonetheless, the decision between state versus federal procedures ultimately comes down to application of jurisdictional rules related to the sale of the power. Therefore, it is not necessary or advisable to apply a size limit to state-jurisdictional procedures. For example, a project may exceed the established size limit on state procedures but still need to obtain a state-jurisdictional interconnection agreement, and in that case, it would not be clear what process the project proponent should go through to obtain an interconnection agreement. Instead, IREC recommends removing the size limit restriction on determining applicability of the procedures and let application depend solely on jurisdictional considerations. The study process traditionally used within most state procedures is generally robust enough to handle projects of any size, though the terms in an interconnection agreement may need to be modified to accommodate larger projects.

> “. . . interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process at recognizes the capabilities of energy storage systems.”

- IREC's *Model Interconnection Procedures* are applicable to all state-jurisdictional interconnections (see Section I.A).
- The FERC SGIP applies to projects up to 20 MW (see Section 1.1.1). Larger projects would proceed under the Large Generator Interconnection Procedures (though some ISOs have eliminated this distinction). Unlike FERC, most states do not have separate procedures for large and small systems, so such a size cap is not necessarily relevant at the state level.

## B. Inclusion of Energy Storage

As energy storage prices continue drop, it will become increasingly attractive for customer to consider installing energy storage systems, either with or without on-site generation systems (such as solar PV). Future policies, incentives and/or tariffs may further facilitate the adoption of energy storage, which is poised to offer a range of benefits to customers directly as well as their utilities. From an interconnection perspective, energy storage can mostly be treated the same as other generation technologies, however for the sake of clarity and transparency, the interconnection procedures should specifically indicate that they cover energy storage, and may also want to consider steps to help ensure an efficient review process that recognizes the capabilities of energy storage systems.

- In its Glossary of Terms in Attachment 1 (see Small Generator Interconnection Agreement (SGIA), Attachment 1) the FERC SGIP explicitly incorporates energy storage by defining "Small Generator Facility" to include devices for the production and/or storage for later injection of electricity. It also allows the utility to not always study the absolute maximum capacity if the applicant demonstrates the system will not be operated in that manner.



- IREC's recent papers, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits* (Feb. 2015) and *Charging Ahead: An Energy Storage Guide for Policymakers* (April 2017) address some considerations regarding the interconnection of energy storage.
- California's Rule 21 Order (issued June 23, 2016) adopted an approach for how both the charging and discharging functions of energy storage systems should be reviewed. The adopted approach ensures that the load from energy storage systems is not treated differently from other types of customer load when it comes to assigning costs for review and upgrades.

### C. Size Limit for Small, Inverter-based System Review, Also Known as "Level 1" Review

The expedited review process for small, inverter-based systems (e.g., solar PV and storage) is intended to allow for a streamlined process for generators that are unlikely to trigger adverse system impacts. This process requires similar, if not identical, technical screening to the Fast Track process (discussed below) but, unlike Fast Track, allows applicants to submit a relatively short, combined application and interconnection agreement. Doing so reduces the time and cost associated with the process for both applicants and utilities, and typically this savings is reflected in the lower fee charged for such applications. Historically, many states allowed systems up to 10 kW to participate in this expedited process because 10 kW reflected the upper limit for most net-metered residential solar PV systems. In recent years, states have begun to raise the eligibility size limit to 25 kW or above in recognition that systems larger than 10 kW may participate in net metering, and systems up to 25 kW are unlikely to cause adverse system impacts and thus can be safely connected with a simple screening process.

- IREC's *Model Interconnection Procedures* permit inverter-based generators up to 25 kW to undergo Level 1 review (see Section III.A.2.a).
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the expedited small, inverter-based system review process and provides the rationales for increasing its size limit to 25 kW (see pp. 15-16).
- Some other states that have size limits that are greater than 10 kW include North Carolina, Ohio, Oregon, Utah and Massachusetts.

### D. Size Limit for Fast Track Review, Also Known as "Level 2" Review

The Fast Track process consists of several technical screens intended to easily identify proposed interconnections that will not threaten the safety and reliability of the electric system, and allow these systems to proceed through an expedited review process. Although the technical screens decide whether a project will be able to interconnect without a full study, an overall size limit for Fast

Track eligibility offers applicants a useful indicator as to whether or not their system is at all likely to pass those screens and serves an administrative function for utilities to help sort projects into the proper study track. In the former iteration of the FERC SGIP and in many states' procedures, Fast Track review is limited to systems up to 2 MW. More recently, FERC and several states have moved away from a broadly applicable cap to a more nuanced, table-based approach, which takes into account location-related factors that affect the likelihood of the generator to have adverse impacts on the electric system. Specifically, the table-based approach allows the size limit to increase as the voltage of the line increases and if a generator is closer to the substation. As with the inverter-based review process discussed above, the robust technical screening process is the ultimate arbiter of whether or not a system can receive Fast Track review. Thus, the rule of thumb in setting size limits should be to allow the largest sized project that could potentially pass the interconnection screens on the particular line size to use the Fast Track procedures. If the project is too large the screens will prevent the project from interconnecting without study. If the size limit is too low, projects could be forced into a multi-month, expensive study process unnecessarily.

- Section III.B.2.a of IREC's *Model Interconnection Procedures* incorporates a table-based approach to Level 2 eligibility.

| Line Voltage | Level 2 (Fast Track) Eligibility | |
|---|---|---|
| | Regardless of Location | On > 600 amp line and < 2.5 miles from substation |
| < 4 kV | < 1 MW | < 2 MW |
| 5 kV – 14 kV | < 2MW | < 3 MW |
| 15 kV – 30 kV | < 3 MW | < 4 MW |
| 31 kV – 60 kV | < 4 MW | < 5 MW |

- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the Fast Track process and the rationale for adopting a table-based approach to eligibility (see pp. 19-21).
- Section 2.1 of the FERC SGIP also incorporates a Fast Track Eligibility table. Compared to the IREC and NREL tables, FERC relies on similar but slightly more conservative numbers that were negotiated during the tariff review process. The following states have also adopted a table based approach to Fast Track: Illinois, Iowa, Ohio, North Carolina, and South Carolina.
- For information on the amount of generation that can be potentially accommodated on different line voltages, see Tom Short, Electric Power Distribution Handbook, CRC Press, Section 1.3 (2004). A pdf version is available here.

### E. Supplemental Review

If an interconnection applicant fails one or more of the Fast Track screens, many states' procedures allow it to undergo "supplemental review" or "additional review" to determine whether or not it could interconnect without full study. Until recently, however, this review was a "black box," providing no details on its scope, cost or process. In its most recent revision to SGIP, FERC integrated a more transparent supplemental review process that relies on three screens, including a penetration screen (Screen 1), set at 100 percent of minimum load. In most cases, if the proposed generation facility is below 100 percent of the minimum load measured at the time the generator will be online, then the risk of power backfeeding beyond the substation is minimal and thus there is a good possibility that power quality, voltage control and other safety and reliability concerns may be addressed without the need for a full study. The other two screens allow for utilities to evaluate any potential voltage and power quality (Screen 2) and/or safety and reliability impacts (Screen 3). Several states, including Ohio, Massachusetts, Illinois, Iowa and California, have adopted this transparent supplemental review process, and it is under consideration in others, including Maine and Minnesota.

In nascent solar markets, supplemental review may not seem immediately valuable, however as penetrations of solar increase, and more projects fail the Fast Track screens, particularly the 15 percent of peak load penetration screen, a transparent supplemental review process will become increasingly important. It provides additional time to resolve some of the safety and reliability concerns identified by the conservative initial review screens while still allowing for transparent, efficient and cost-effective interconnection of projects.

- Section 2.4 of the FERC SGIP describes its Supplemental Review process and the support for using a 100 percent of minimum load screen in it.
- IREC's *Model Interconnection Procedures* incorporate a nearly identical supplemental review process in Section III.D.
- NREL's *Updating Small Generator Interconnection Procedures for New Market Conditions* explains the rationale for a transparent supplemental review process and refers to California's process, which served as a model for the FERC SGIP (see pp. 30-31).
- This approach is currently used in California, Massachusetts, Hawaii, Illinois, Iowa, New York and Ohio.

## II. Improving the Timeliness of the Interconnection Process

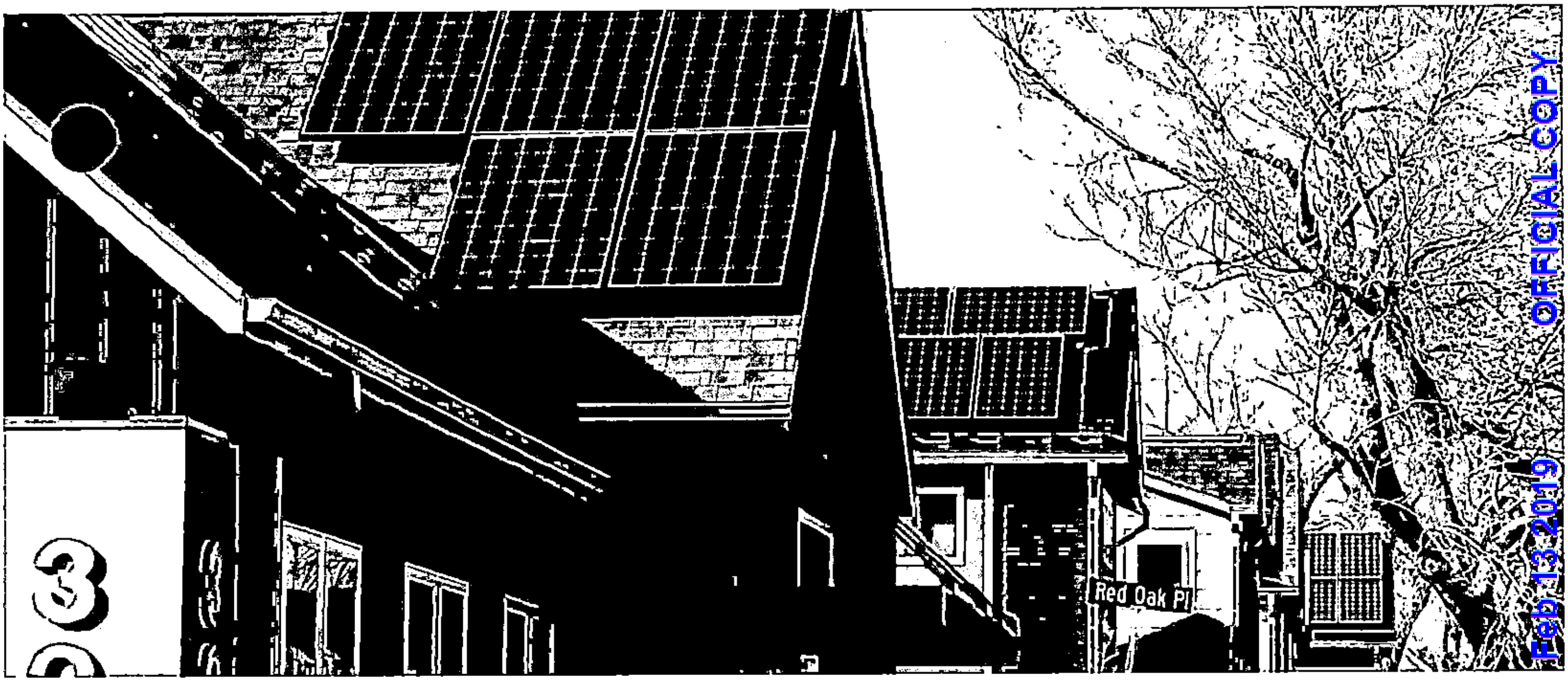
Below are some methods that could be considered to improve the timeliness of the interconnection process. In addition to these subsections, also note that a number of the other recommendations in this memorandum are likely to also assist with improving the timeliness of the interconnection process. In particular, the pre-application report can reduce the number of unrealistic project applications that have to be reviewed and also improve the quality of the application submittals, which speeds up the review process. The use of a robust Supplemental Review process can help move projects more efficiently through the process by requiring fewer projects to go to study and also giving developers information about their likely project costs earlier (this often means projects can make a decision whether to proceed in a more efficient manner). Finally, the section below on reporting requirements is likely to also have a significant impact on utility compliance with deadlines because they will be required to report delays to the Commission.

### A. Electronic Application Submittal, Tracking and Signatures

One method for increasing the speed and efficiency of the interconnection process for both customers and utilities is to enable the use of technology to expedite the processing of applications. IREC's *Model Interconnection Procedures* include provisions that would allow for electronic submittal of applications and electronic signature of interconnection documents. In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays. A number of utilities across the country utilize electronic submittal and processing techniques. Two California utilities have reported millions in dollars in annual savings through successful adoption of an electronic submittal and tracking process that has dramatically reduced processing times for NEM applications.[1]

"In addition to being able to submit an application electronically, it is helpful to have an online interface wherein customers can track the progress of their application and be notified quickly of any deficiencies or delays."

1. K. Ardani & R. Margolis, *Decreasing Soft Costs for Solar Photovoltaics by Improving the Interconnection Process: A Case Study of Pacific Gas and Electric*, at 7 (Sept. 2015), National Renewable Energy Laboratory, available at: www.nrel.gov/docs/fy15osti/65066.pdf; Electric Power Research Institute, PV Integration Case Study: SDG&E's Distributed Interconnection Information System (DIIS), *Solar PV Market Update, Volume 10: Q2 2014*, at 4 (June 2014), available at: https://www.sdge.com/sites/default/files/documents/1508554296/EPRI%20DIIS%20Case%20Study.pdf






### B. Ensure That Projects are Cleared from the Queue If They Do Not Progress

One way to better enable utilities to keep up with the timelines set forth in the procedures is to make sure they are focusing their efforts on projects that are ready to move forward. It is often true that interconnection backlogs can be due to delays on the customer's end and not just by the utility. Particularly for projects in the study process, it is important that they keep up with their responsibilities in the tariff or that they withdraw. Failure to do so results in delays for all projects that are later in the queue. Since projects are studied "serially" in most cases, projects stalled in the queue effectively reserve capacity that should be made available to later queued projects at some point. Massachusetts, California, North Carolina and New York have all recently adopted processes that allow projects to be removed from the queue if they fail to move forward in an efficient manner.

### C. Include Timelines for Construction of Upgrades and Meter Installs

It is often the case that interconnection procedures contain detailed timelines for the interconnection application review process, but little if any detail regarding the timeliness of the steps that have to be taken after an interconnection agreement is signed. Procedures should include specific and enforceable timelines for construction upgrades and meter installs to avoid unnecessary delays once interconnections are approved.

### D. Implement a More Efficient Dispute Resolution Process

When delays do arise due to disagreements about the rules, technical requirements or costs, developers often do not seek to resolve them through existing dispute resolution procedures because those processes can often drag out longer than the delay. In addition, developers are often hesitant to use those procedures for fear that it will damage their working relationship with the utility going forward. One strategy for states to consider is to appoint an ombudsman within the Commission, or at the utility, to who could help facilitate resolution of minor complaints in a timely manner. New York and Massachusetts use ombudspersons within the Commission to help resolve disputes, and Minnesota used an ad hoc process involving outside engineers to help mediate interconnection disputes. Another option would be to appoint a technical master to help facilitate resolution of disputes regarding technical requirements.

### E. Implement Enforcement Measures for Utility Compliance

Interconnection standards should contain clear requirements for when utilities and customers must complete each step of the interconnection process. In addition, there should be a meaningful mechanism to enforce compliance with the timelines. This has been a challenging issue across the United States with very few state policies that provide for meaningful enforcement. The only significant example comes from Massachusetts, which recently approved a "timeline enforcement mechanism," which would impose monetary penalties on the utilities if they fail to meet timelines specified within the interconnection procedures.[2] The proposed mechanism was developed collaboratively and submitted jointly by utilities, developers, and the Massachusetts Department of Energy Resources. New York has adopted an "earnings adjustment mechanism" that connects utilities' performance incentives (and/or penalties) on interconnection timelines and customer satisfaction with the process.

> "Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing."

## III. Improving Grid Transparency and Access to Information

### A. Transparency and Reporting Requirements

Transparency and reporting regarding the interconnection process, and specifically the interconnection queue—that is, the order projects proceed through the process and their status—can be beneficial for interconnection applicants as well as utility regulators and others interested in understanding the process. Publication of an interconnection queue, along with regular reporting can allow applicants to see how many projects require utility review before them and the status of their review, thereby giving them a more realistic sense of timing. In addition, similar to the pre-application report and distribution system mapping discussed below, a public interconnection queue can show where applicants earlier in the queue are located, and therefore help later applicants determine which locations may have limited capacity and thus would be more likely to require costly interconnection review. A public interconnection queue and regular reporting can also help to identify bottlenecks or other problems for utilities and regulators to address.

- The Massachusetts Department of Energy Resources (DOER) collects monthly data from the utilities, which it provides on a publicly accessible website (click on "Interconnection activity").
- In California, each utility has a detailed interconnection queue:
  - Pacific Gas and Electric Company (PG&E) (see "What's New: Public Queue").
  - San Diego Gas & Electric Company (SDG&E) (see "SDG&E Generation Interconnection Request Queue (WDAT & Rule 21)").
  - Southern California Edison Company (SCE) (see "Public WDAT-Rule 21 Queue").
- The Hawaiian Electric Company (HECO) provides an Integrated Interconnection Queue for interconnections on Hawaii and Maui.

### B. Utility Distribution System Maps

Similar to the pre-application reports, discussed below, utility maps can help potential interconnection applicants to evaluate siting options for their projects and avoid wasted resources spent on evaluating interconnection applications for projects located at poor grid locations that will never be built. In

2. Mass. Dept. of Pub. Utils., DPU 11-75-F, Order on a Timeline Enforcement Mechanism (July 31, 2014) (Appendix B to the order contains a clean version of the mechanism) and DPU 11-75-G, Order on the Model Interconnection Tariff (May 4, 2015).



particular, maps can identify grid characteristics (e.g., substation or line capacity, existing generation capacity on a line, available capacity for new generation, etc.) and areas of the grid that can accommodate new generation as well as areas that cannot accommodate new generation without significant upgrades (i.e., at a significant cost). Maps can also identify areas where projects might provide system benefits. When this kind of information is provided in advance in a publicly accessible way, potential applicants can use it to narrow down locations for their projects and submit fewer dead-end applications. Although maps can take some resources upfront to develop, they can save utilities time and money in the long run because they do not have to respond to individual information requests or evaluate applications submitted only to get the locational information that will instead be provided via the maps.

- The New York utilities have all recently launched maps that provide information on good potential points of interconnection.
- ComEd has more basic maps for its service territory in Illinois.
- The Hawaiian Electric Company (HECO) provides "Locational Value Maps" that provide an indication of the percentage of DG on the utilities' distribution circuits.
- Delmarva Power provides a map of "restricted circuits" in their territory in Delaware.
- The California utilities have some of the most robust maps available today. Originally called "preferred location" maps, they are now evolving to include full hosting capacity information.
  - Southern California Edison (SCE) (click "Content" on left side of page and zoom in on map to see detail)
  - Pacific Gas & Electric (PG&E) (registration required)
  - San Diego Gas & Electric (SDG&E) (registration required)
- Minnesota and Maryland are undertaking similar processes as part of their grid modernization proceedings.
  - Pepco, a regulated electric utility serving customers in Maryland and the District of Columbia, has developed a detailed hosting capacity map that provides available capacity at the distribution feeder level.

### C. Pre-application Reports

While maps can provide a helpful, high-level picture of optimal and non-optimal grid locations, pre-application reports can allow potential applicants to obtain more granular information about potential project locations. The pre-application report is intended to require limited effort from the utility and, in most cases, relies entirely on pre-existing data. Pre-application reports can be optional or mandatory for all or some subset of projects, such as larger projects expected to have greater system impacts. Most pre-application reports require a relatively minimal fee (e.g., $300).

Since first introduced in California, pre-application reports have been widely accepted as a useful tool by both developers and utilities in all states IREC has appeared in recently. Indeed, California recently expanded their pre-application process to include an "enhanced" report that allows potential applicants to obtain more site-specific information that can sometimes require a utility truck-roll in exchange for an additional fee.

- The Federal Energy Regulatory Commission (FERC) has incorporated a pre-application report requirement into Section 1.2 of its Small Generator Interconnection Procedures (SGIP), which were revised in 2013.
- IREC's *Model Interconnection Procedures* (2013) include a pre-application report in Section II. In addition, IREC has developed a model pre-application request form for use in North Carolina and Illinois that could be easily modified for South Carolina.
- Finally, a paper published by the National Renewable Energy Laboratory, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012), pp. 12-15, provides an explanation of why pre-application information is so valuable.

Other states that have adopted a pre-application report include Massachusetts, Iowa, Illinois, Ohio, North Carolina, South Carolina, and New York.

Taking the mapping and pre-application reporting components one step further, some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection. A hosting capacity analysis determines how much capacity there is for additional distributed energy resources (load or generation) at precise points on the grid without the need for traditional upgrades to the system. In addition to the map interface, a hosting capacity analysis will also include downloadable data that will provide applicants with the detailed load curves for particular sites that can significantly assist with "right-sizing" of projects for each location.

## IV. Allowing Construction for Level 1 & 2 Projects

Many state procedures and the FERC SGIP force a project to fail a Level 1 or 2 screen if the project would require any construction to be interconnected. Some states allow construction through the supplemental review process, but often this process is not well used. The effect of this screen is that a project may have been determined to not pose any system impacts (which is what the other technical screens evaluate), but still have to go through the full study process simply to determine the costs of any upgrades. In some cases, utilities do not adhere strictly to this rule and allow some construction. As utilities have gained more experience with the interconnection of distributed generation facilities it has become apparent that it is not necessary to send a project to the full study process just because some construction is required. If a project triggers construction after having passed the other Level 1 or 2 screens it means that the required construction does not require a system impacts study, and it is likely the construction is minor enough that a full facilities study is not warranted either. For example, it is common for a project to need to have interconnection facilities constructed. Interconnection facilities do not have upstream impacts and thus there is not a need to conduct a full system impacts study in order to move ahead with approving the project. In addition,

> "... some states and utilities have begun to conduct hosting capacity analyses that allow potential interconnection applicants to access significantly more detailed and accurate information about the state of the grid at the proposed point of interconnection."

> "Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency."

some utilities have recognized that it is more efficient for them to allow the upgrading of line transformers and certain other equipment at this stage. Thus, a process has been developed to allow Level 1 & 2 projects to still proceed even if they require construction. For minor construction, a cost estimate is provided, and for more significant upgrades, a utility may opt to prepare a Facilities Study.

- FERC approved modifications to the wholesale tariffs of SCE and PG&E to allow for certain construction in 2011. It also included a process to allow projects in the supplemental review process to proceed even if some construction is required.
- Numerous states have moved away from using a no construction screen, including North Carolina, Illinois, South Carolina, California and Massachusetts.

## V. Consolidating the Study Process

When projects are either ineligible for or fail to pass through expedited review they must undergo a more thorough study process in order for the utility to be able to determine what system impacts the project may pose, to design solutions to mitigate for any impacts, and to identify and allocate the costs for these solutions. Following the lead of the FERC LGIP and SGIP, many state procedures contain a three-tier study process, which includes a feasibility study, a system impacts study, and a facilities study. Altogether the processing of three layers of study can take many months. Many utilities and interconnection applicants are discovering, however, that the feasibility study is not necessary or valuable in all cases and can be eliminated in the interest of time and cost efficiency.

- Some states such as Minnesota, New York, and Nevada have a single study that combines the assessment of system impacts with the determination of the upgrade costs. This can result in a more efficient review process, but it also means that an applicant may end up paying for the development of a cost estimate even if they would be unlikely to proceed after learning of the system impact results.
- Other states have started to just eliminate the feasibility study in favor of a two-tier study process, including North and South Carolina.
- A paper published by NREL, *Updating Small Generator Interconnection Procedures for New Market Conditions* (2012), pp. 31-36, provides a discussion of possible methods to improve the efficiency of the study process itself.

## VI. Determination of Upgrade Costs

Once a utility has examined the potential impact a project may have on the system they may identify upgrades that need to be completed to allow the project to go forward. The process for determining upgrade costs, providing estimates, and ensuring those estimates are meaningful has been a source of considerable discussion in many high penetration states lately. There are three central concepts: cost predictability, cost certainty, and cost allocation. There are not yet clearly established best practices in these areas, but there are a few key practices that are beginning to take hold and warrant consideration.


- **Cost Tables:** At the transmission level it is common for Independent System Operators (ISOs) and Regional Transmission Organization (RTOs) to publish cost tables that show the prices of typical equipment to enable customers to have a better sense of the expected cost of undertaking specific upgrades. The California utilities agreed to publish a cost table for distribution level interconnections as well. In addition to helping provide more transparency and predictability into the interconnection costs, this process also can reduce concerns about utility manipulation of cost estimates.
- **Cost Envelopes:** Massachusetts was the first state to implement a process that requires the utilities to provide a binding cost estimate to interconnection applicants. Depending upon what stage the customer requests the estimate, it cannot exceed the estimated amount by either 25% (if sought earlier in the process) or 10% (if obtained at the end of the review process). This cost envelope approach means that the utility is responsible for any costs that exceed those inflation amounts. California recently implemented a similar cost envelope process, using a 25% threshold, and allowing utilities to seek rate recovery for overages if they can show their failure to accurately estimate the costs was reasonable. New York's new rules contain softer language that could impose a greater burden on utilities to provide accurate estimates.
- **Detailed Cost Estimates:** Another way to improve the transparency of the interconnection upgrade cost process is to require that utilities provide more detail in their interconnection cost estimates. Though it varies by utility, often cost estimates contain no more than one bulk figure with no further information on the cost of the components and labor that make up that cost. Instead, the estimate given could provide a list of the major equipment required and particular prices along with a breakdown of the utility time that will be spent reviewing and constructing the upgrades. Providing detailed estimates should improve the accuracy of the estimates and also the confidence the applicant has that the costs assessed are being charged at reasonable rates.
- **Cost Allocation:** How interconnection costs are divided between different interconnection customers is a topic that has been raised in various states in recent years, but there has not yet been considerable progress in developing functional mechanisms that improve the allocation of costs across responsible customers. The distribution level interconnection process typically operates on a cost causation principle that assigns the full cost of system upgrades to the first project that triggers the need for them. This applicant will bear the full cost of the upgrade, although projects before them may have contributed to the need for the upgrade, and later queued projects may also take advantage of the increased capacity

created by the upgrade. This process creates perverse incentives and behavior in many cases, can be a central cause of queue backlogs, and prevent upgrades from occurring that might be economically efficient if spread across all potential beneficiaries. On the transmission system costs are usually paid back over a period of years since the system is networked and the idea is that all projects ultimately benefit the system. However, more limited examples of cost sharing exist on the distribution system.

- Some states such as California and Massachusetts have experimented with "group studies" on the distribution system, and Massachusetts' standards contain a rule that requires allocation of costs across customers, but it is not clear how often this rule is actually applied.[3]
- New York just launched one of the first examples of a formal cost sharing mechanism for projects that are not being studied concurrently. For upgrades of a certain type and cost, the generator that first triggers the need for the project will cover all the costs upfront, but a mechanism has been put in place to require later projects to reimburse the first project if they connect within a defined period of time.

3. MA DPU Order 11-75-G (Revised Tariffs), Section 5.4 ("Should the Company combine the installation of System Modifications with additions to the Company's EPS to serve other Customers or Interconnecting Customers, the Company shall not include the costs of such separate or incremental facilities in the amounts billed to the Interconnecting Customer for the System Modifications required pursuant to this Interconnection Tariff. The Interconnecting Customer shall only pay for that portion of the interconnection costs resulting solely from the System Modifications required to allow for safe, reliable parallel operation of the Facility with the Company EPS.").

## Additional Resources


- Interstate Renewable Energy Council, Model Interconnection Procedures, (April 2013), available at: http://www.irecusa.org/publications/model-interconnection-procedures/ (last accessed June 5, 2017).

- Sky Stanfield et al., *Charging Ahead: An Energy Storage Guide for State Policymakers*, Interstate Renewable Energy Council, (April 2017), available at: http://www.irecusa.org/publications/charging-ahead-an-energy-storage-guide-for-policymakers/ (last accessed June 5, 2017).

- Sky Stanfield and Amanda Vanega, *Deploying Distributed Energy Storage: Near-Term Regulatory Considerations to Maximize Benefits*, Interstate Renewable Energy Council, (February 2015), available at: http://www.irecusa.org/publications/deploying-distributed-energy-storage/ (last accessed June 5, 2017).

- Erica McConnell and Laura Beaton, *You Snooze, You Lose: Enforcing Interconnection Timelines for Everyone Involved*, Greentech Media, (December 2016), available at: https://www.greentechmedia.com/articles/read/you-snooze-you-lose-enforcing-interconnection-timelines-for-everyone-involv (last accessed June 5, 2017).

- Erica McConnell, *Experiencing Holiday Traffic or Airport Security Lines? That's How Interconnection Queues Feel for Solar, Greentech Media*, (November 2016), available at: https://www.greentechmedia.com/articles/read/sick-of-airport-security-lines-think-about-how-solar-companies-feel-in-inte (last accessed June 5, 2017).

- Erica McConnell and Cathy Malina, *Interconnection: The Key to Realizing Your Distributed Energy Policy Dream*, Greentech Media, (October 2016), available at: https://www.greentechmedia.com/articles/read/interconnection-the-key-to-realizing-your-distributed-energy-policy-dream (last accessed June 5, 2017).

- Chelsea Barnes et al., *Comparing Utility Interconnection Timelines for Small-Scale Solar PV: 2nd Edition*, EQ Research, (October 2016), available at: http://eq-research.com/wp-content/uploads/2016/10/EQ-Interconnection-Timelines-2016.pdf (last accessed June 5, 2017).

- Kristen Ardani et al., *State-Level Comparison of Processes and Timelines for Distributed Photovoltaic Interconnection in the United States*, National Renewable Energy Laboratory, (January 2015), available at: http://www.nrel.gov/docs/fy15osti/63556.pdf (last accessed June 5, 2017).

- Vote Solar and the Interstate Renewable Energy Council, *Freeing the Grid*, website, available at: http://freeingthegrid.org/#state-grades/ (last accessed June 5, 2017).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## ABOUT IREC

The Interstate Renewable Energy Council increases access to sustainable energy and energy efficiency through independent fact-based policy leadership, quality work force development, and consumer empowerment. Our vision: a world powered by clean sustainable energy where society's interests are valued and protected.

IREC is an independent, not-for-profit 501(c)(3) organization that relies on the generosity of donors, sponsors, and public and private program funder support to produce the successes we've been at the forefront of since 1982.

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# Exhibit SBA-Direct-8

Interstate Renewable Energy Council
Data Request No. 1
Docket No. E-100, Sub 101
NCIP
Item No. 1-1



**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

Please provide copies of all responses to data requests or formal discovery requests provided to all other parties in the above-referenced docket. This is a continuing request.

**Response**:

DEC and DEP will provide responses to all data requests provided to other parties in this proceeding and will consider this an ongoing request.

Interstate Renewable Energy Council
Data Request No. 1
Docket No. E-100, Sub 101
NCIP
Item No. 1-2



**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

Please provide the following information related to interconnection timelines.

a. For the < 20 kW Small Inverter Process, for the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when Duke received an Interconnection Request (section 2.2) until when Duke has returned the signed Interconnection Application/Agreement (section 2.2.1).

b. For the past three years, for all projects, provide data regarding the median, mean, shortest, and longest periods of time from when Duke received an Interconnection Request (section 1.4.1) until when Duke provided notification to the Interconnection Customer stating whether the Interconnection Request was considered complete and valid (section 1.4.3).

c. For the Fast Track process, for the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when an Interconnection Request was considered complete (section 1.4.3) and valid, until when Initial Review results were provided to the Applicant (section 3.2).

d. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when passing Initial Review results were provided to the Applicant (section 3.2) and no construction was required, until when Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1).

e. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when passing Initial Review results were provided to the Applicant (section 3.2) and only minor utility construction was required, until when Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.2).

f. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when an Applicant agrees to Supplemental Review (section 3.4) and the Supplemental Review fee is submitted, until when the Supplemental Review results are provided to the Applicant (section 3.4.1).

g. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when passing Supplemental Review results were provided to the Applicant (section 3.4.1) until when Duke has provided the Applicant with a Generator Interconnection Agreement, where no modifications to the facility were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.1).

h. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when passing Supplemental Review results were provided to the

Applicant (section 3.4.1) until when Duke has provided the Applicant with a Generator Interconnection Agreement, where facility modifications were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.2).

i. For the past three years, provide data regarding the median, mean, shortest, and longest periods of time from when passing Supplemental Review results were provided to the Applicant (section 3.4.1) until when Duke has provided the Applicant with a Generator Interconnection Agreement, where minor modifications to the Utility's System were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.3).

j. For the past three years, for projects undergoing only Fast Track review (Initial Review and Supplemental Review), provide data regarding the median, mean, shortest, and longest periods of time from when Duke provided notification to the Interconnection Customer stating the Interconnection Request is considered complete (section 1.4.3), until when the Generator Interconnection Agreement is executed by both parties.

k. For the past three years, for projects undergoing the Section 4 Study Process, provide data regarding the median, mean, shortest, and longest periods of time from when the Scoping Meeting is held (section 4.2.1), until when the Interconnection Customer has received all study results under sections 4.3 and 4.4.

l. For the past three years, for projects undergoing the Section 4 Study Process, provide data regarding the median, mean, shortest, and longest periods of time from when the Interconnection Customer has received all study results under sections 4.3 and 4.4, until when Duke has provided the Applicant with a Generator Interconnection Agreement (section 5.2.1).

m. For the past three years, for projects undergoing the Section 4 Study Process, provide data regarding the median, mean, shortest, and longest periods of time from when Duke provided notification to the Interconnection Customer stating the Interconnection Request is considered complete (section 1.4.3), until when the Generator Interconnection Agreement is executed by both parties(section 5.2.1).

n. How many projects are currently in Duke's queues that have Interconnection Requests that have been deemed complete but that have not yet received Generator Interconnection Agreements?

<u>Response</u>:

**Duke Response 1-2a.**

a. The system of record currently used by the Companies to process ≤ 20 kW projects in NC and SC is PowerClerk. Management reporting is done on a monthly basis to track compliance with communication to customers. This reporting tracks: (1) the communication required to be sent within 3 business days verifying receipt of IR and (2) the communication required to be sent within 10 business days verifying either completeness of IR information or indicating what information is missing from the IR to render it complete. The Companies are answering this request based upon readily-available information in the Power Clerk system comparing IR Received Dates to Commercial Operation-Power Generation in Progress Dates for Projects ≤20 kW:

| | 2016 | 2017 | YTD 9/30/18 |
|---|---|---|---|
| | | | |
| Mean | 36 | 43 | 39 |
| Median | 26 | 32 | 35 |
| Shortest | 0 | 0 | 0 |
| Longest | 421 | 326 | 167 |

For ≤ 20 kW applications, there is no formal Interconnection Agreement in the NC Interconnection Procedures, which is why the above chart compares IR Received Date to Commercial Operation-Power Generation in Progress Dates for these projects. If the application is complete, the Renewables Service Center sends the Interconnection Customer the "Contingent Approval to Interconnect the Generating Facility" portion of Attachment 6 to the NC Interconnection Procedures as part of the first 10 day communication sent to the Interconnection Customer under Section 1.4.4. If the application is incomplete, the Renewables Service Center sends, within 10 business days, notification to the Interconnection Customer clarifying what is missing from the Interconnection Application. The Renewables Service Center tracks compliance with the 10 day communication requirement. Below are summaries of data provided based on readily available Reports for years 2016, 2017 and 2018 tracking 10 day communication compliance.

2016 Metric at **86.7% Compliance**: Of 962 IRs received in DEC/DEP NC, 128 did not meet the 10-business day timeline. 121 of these missed dates occurred in January and February of 2016. Process improvements were implemented and, after improvements, communication within the 10-day period improved significantly.

2017 Metric at **99.9% Compliance**: Of 1,418 IRs received in DEC/DEP NC, only 1 did not meet the 10-day business day communication timeline.

2018 Metric at **99.9% Compliance**: Of 2,975 IRs received in DEC/DEP NC, only 4 did not meet the 10-day business day communication timeline.

**Duke Response 1-2b.**

b. Data Calculated based on IR Received Dates compared to 10 Day Complete Dates (in Calendar Days versus Business Days):

| | 2016 (297 Missing IR or 10 Day Date) | 2017 (61 Missing IR or 10 Day Date) | YTD 9/30/18 (188 Missing IR or 10 Day Date) |
|---|---|---|---|
| Total | 940 | 1,490 | 2,628 |
| Mean | 7.4 | 4.9 | 8.9 |
| Median | 2.3 | 2.2 | 3.7 |
| Shortest | 0.0 | 0.3 | 0.0 |
| Longest | 252.4 | 267.3 | 195.2 |

Data tracking compliance to the 10 business day notification requirement for the expedited Section 2 process for ≤ 20 kW projects is provided in the chart above. The same communication process for projects > 20 kW is not tracked by the Renewables Service Center. Data tracking median, mean, shortest and longest time frames from IR Received date until 10 Day Communication date is not available.

Below are summaries of data based upon readily available Reports for years 2016, 2017, and 2018.

2016 Metric at 100.0% Compliance: Of 169 IRs received in DEC/DEP NC, all 169 met the 10-business day communication timeline.

2017 Metric at 87.1% Compliance: Of 132 IRs received in DEC/DEP NC, 17 did not meet the 10-business day communication timeline.

2018 Metric at 100.0% Compliance: Of 162 IRs received in DEC/DEP NC year-to-date 9/30/2018, all 162 met the 10-business day communication timeline.

**For Duke Responses 2c – 2m the following assumptions apply:**

As discussed during the conference call held between counsel for IREC and counsel for Duke Energy on October 29, 2018, IREC's request for quantification (median, mean, shortest, and longest) of interconnection study data "for the past three years" is unduly burdensome and would require Duke Energy personnel to expend significant manual effort to quantify, capture, and validate data for accuracy and completeness as the requested data is not readily available in the Salesforce system of required. Duke Energy has made a good faith effort to review and validate data for Section 3 and Section 4 IRs that had a queue number issued after January 1, 2016, excluding any project that had an IA executed prior to 2018. This more granular data set is readily available and its accuracy previously validated for internal reporting purposes.

Salesforce also does not track the exact requested start and end dates as stated in many instances, however to accommodate the request in all instances we made an effort to provide our nearest equivalent to what was requested. Those qualifiers are listed under the specific requests below. The data includes time durations in units of Business Days, excluding federal holidays. To the extent the data provided is not satisfactory to IREC, Duke Energy reserves its rights to object to these requests.

IREC Request_2c_2n_Fina    IREC Request_Redacted_

**Duke Response 1-2c.**

c. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2c in response to this request. "Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid." "FastTrack Study End Date" is Duke's nearest equivalent of when "Initial Review results were provided to the Applicant (section 3.2)."

**Duke Response 1-2d.**

d. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2d in response to this request. Duke Energy does not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. However, only one project in our data set passed the FastTrack screen in 2018, it took 3 days from when passing Initial Review results were provided to the Applicant (section 3.2) and no construction was required, until when Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1). It did not require any utility construction, and the project was a 24 kW net meter project, with a 170 kW peak load.

**Duke Response 1-2e.**

e. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2e in response to this request. Duke Energy does not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects.

**Duke Response 1-2f.**

f. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2f in response to this request. "Supplemental Study Start Date," when Duke begins the Supplemental Review, is Duke's nearest equivalent to when "Applicant agrees to Supplemental Review (section 3.4) and the Supplemental Review fee is submitted." "Supplemental Study End Date," when Duke completes the Supplemental Review, is Duke's nearest equivalent to when "the Supplemental Review results are provided to the Applicant (section 3.4.1)."

**Duke Response 1-2g.**

g. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2g in response to this request. Duke Energy does not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. "Supplemental Study Start Date," is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1)." Additionally, projects with the absence of a SIS start date, and/or that did not have an IA Sent Date were excluded; it was assumed that they did not pass the Supplemental Review. "IA Sent Date," when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where no modifications to the facility were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.1)."

**Duke Response 1-2h.**

h. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2h in response to this request. Duke Energy does not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. "Supplemental Study Start Date, is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1)." Additionally, projects with the absence of an SIS start date, and/or that did not have an IA Sent Date were excluded; it was assumed that they did not pass the Supplemental Review. "IA Sent Date," when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where facility modifications were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.2)."

**Duke Response 1-2i.**

i. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2i in response to this request. Duke Energy does not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. "Supplemental Study Start Date," is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1)." Additionally, projects with the absence of a "System Impact Study Start Date," and/or that did not have an "IA Sent Date" were excluded; it was assumed that they did not pass the Supplemental Review. "IA Sent Date," when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where minor modifications to the Utility's System were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.3)."

**Duke Response 1-2j.**

j. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2j in response to this request. "Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid." "IA Executed Date," when Duke receives the executed IA from the customer, is Duke's nearest equivalent of when "the Generator Interconnection Agreement is executed by both parties.".

**Duke Response 1-2k.**

a. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2k in response to this request. "System Impact Study Start Date" is Duke's nearest equivalent to when "the Scoping Meeting is held (section 4.2.1)". "Facility Study End Date" is Duke's nearest equivalent of when "when the Interconnection Customer has received all study results under sections 4.3 and 4.4." There were roughly 58 System Impact Studies (Section 4.3) that were completed for projects that entered the queue after January 2016 and that satisfied the qualifiers within our dataset, however only 15 projects completed Facilities Studies (Section 4.4) and therefore a large number of samples were excluded; the Section 4.4 study was the limiting aspect of this request and the subsequent requests of 2l and 2m. Furthermore, many additional SISs would have been completed, but they would have entered the queue prior to 2016 during the time period.

**Duke Response 1-2l.**

b. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2l in response to this request. "Facility Study End Date" is Duke's nearest equivalent of when "when the Interconnection Customer has received all study results under sections 4.3 and 4.4". "IA Sent Date," when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1)." Duke uses Salesforce to track projects through the interconnection process. In all cases reflected in this data, the facility study end date was automatically populated into Salesforce when the operational status for each project was changed within the software from Facility Study Complete to Construction-Pending IA/Customer Payment. In reality, an Interconnection Agreement is sent to an Interconnection Customer at a time after the facility study concludes in compliance with the North Carolina Interconnection Procedures.

**Duke Response 1-2m.**

c. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2m in response to this request. "Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid." "IA Executed Date," when Duke receives the executed IA from the customer, is Duke's nearest equivalent of when "the Generator Interconnection Agreement is executed by both parties."

**Duke Response 1-2n.**

d. See attached excel spreadsheet labeled "IREC Request 2c to 2n Final_Rev2," sheet 2n in response to this request. "Queue # Issue Date" is Duke's nearest equivalent to "projects are currently in Duke's queues that have Interconnection Requests that have been deemed complete." The absence of an "IA Sent Date," is Duke's nearest equivalent to projects that "have not yet received Generator Interconnection Agreements."

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 40 | 20 | 2 | 213 |
| "Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid". | | | | |
| "FastTrack Study End Date" is Duke's nearest equivalent of when "Initial Review results were provided to the Applicant (section 3.2)". | Sample Size: 127 | | | |

Duke Response 1-2c.

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 3 | 3 | 3 | 3 |
| We do not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. | | | | |
| However, only one project in our data set passed FastTrack screen in 2018, it took 3 days from when passing Initial Review results were provided to the Applicant (section 3.2) and no construction was required, until when Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1). It did not require any utility construction, and the project was a 24 kW net meter project, with a 170 kW peak load. | Sample Size: 1 | | | |



**Duke Response 1-2d.**

| Assumptions | Mean | Median | Shortest | Longest |
| --- | --- | --- | --- | --- |
| Business days were used, excluding holidays for all data. | 3 | 3 | 3 | 3 |
| We do not track data related to whether construction was required for particular projects. | | | | |
| However, only one project in our data set passed FastTrack screen in 2018, it took 3 days from when passing Initial Review results were provided to the Applicant (section 3.2) and no construction was required, until when Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1). It did not require any utility construction, and the project was a 24 kW net meter project, with a 170 kW peak load. | Sample Size: 1 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 38 | 20 | 1 | 233 |
| "Supplemental Study Start Date", when Duke begins the Supplemental Review, is Duke's nearest equivalent to when "Applicant agrees to Supplemental Review (section 3.4) and the Supplemental Review fee is submitted". | | | | |
| "Supplemental Study End Date", when Duke completes the Supplemental Review, is Duke's nearest equivalent to when "the Supplemental Review results are provided to the Applicant (section 3.4.1)". | Sample Size: 57 | | | |

Duke Response 1-2f

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 22 | 13 | 2 | 172 |
| We do not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. | | | | |
| "Supplemental Study Start Date", is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1) ". Additionally, projects with the absence of an SIS start date, and/or that did not have an IA Sent Date were excluded; it was assumed that they did not pass the Supplemental Review. | | | | |
| "IA Sent Date", when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where no modifications to the facility were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.1)". | Sample Size: 34 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 22 | 13 | 2 | 172 |
| We do not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. | | | | |
| "Supplemental Study Start Date", is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1) ". Additionally, projects with the absence of an SIS start date, and/or that did not have an IA Sent Date were excluded; it was assumed that they did not pass the Supplemental Review. | | | | |
| "IA Sent Date", when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where facility modifications were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.2)". | Sample Size: 34 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 22 | 13 | 2 | 172 |
| We do not track data related to whether utility construction, facility modifications, or utility system modifications were required for particular projects. | | | | |
| "Supplemental Study Start Date", is Duke's nearest equivalent to when "passing Supplemental Review results were provided to the Applicant (section 3.4.1) ". Additionally, projects with the absence of an SIS start date, and/or that did not have an IA Sent Date were excluded; it was assumed that they did not pass the Supplemental Review. | | | | |
| "IA Sent Date", when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke has provided the Applicant with a Generator Interconnection Agreement, where minor modifications to the Utility's System were required to interconnect the proposed facility consistent with safety, reliability, and power quality standards (section 3.4.1.3)". | Sample Size: 34 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 90 | 77 | 33 | 387 |

"Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid".

"IA Executed Date", when Duke receives the executed IA from the customer, is Duke's nearest equivalent of when "the Generator Interconnection Agreement is executed by both parties".

Sample Size: 25

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 367 | 404 | 209 | 516 |
| "System Impact Study Start Date" is Duke's nearest equivalent to when "the Scoping Meeting is held (section 4.2.1)." | | | | |
| "Facility Study End Date" is Duke's nearest equivalent of when "the Interconnection Customer has received all study results under sections 4.3 and 4.4." | Sample Size: 15 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 2 | 1 | 1 | 11 |
| "Facility Study End Date" is Duke's nearest equivalent of when "when the Interconnection Customer has received all study results under sections 4.3 and 4.4". | | | | |
| "IA Sent Date", when Duke mails the IA to the customer, is Duke's nearest equivalent of when "Duke provided the Applicant with a Generator Interconnection Agreement (section 3.2.2.1)". | | | | |
| Duke uses Salesforce to track projects through interconnection process. In all cases reflected in this data, the facility study end date was automatically populated into Salesforce when the operational status for each project was changed within the software from Facility Study Complete to Construction- Pending IA/Customer Payment. In reality, an Interconnection Agreement is sent to an Interconnection Customer at a time after the facility study concludes in compliance with the North Carolina Interconnection Procedures. | Sample Size: 15 | | | |

| Assumptions | Mean | Median | Shortest | Longest |
|---|---|---|---|---|
| Business days were used, excluding holidays for all data. | 462 | 464 | 333 | 551 |
| "Queue # Issue Date" is Duke's nearest equivalent to when an "Interconnection Request was considered complete (Section 1.4.3) and valid". | | | | |
| "IA Executed Date", when Duke receives the executed IA from the customer, is Duke's nearest equivalent of when "the Generator Interconnection Agreement is executed by both parties". | Sample Size: 14 | | | |

| Assumptions | Total Projects |
|---|---|
| "Queue # Issue Date" is Duke's nearest equivalent to "projects are currently in Duke's queues that have Interconnection Requests that have been deemed complete". | 209 |
| The absense of an "IA Sent Date", is Duke's nearest equivalent to projects that "have not yet received Generator Interconnection Agreements". | |

| Project Queue Number | Operational Status | Sub Status | Status | Facility: Project Identifier | Distribution or Transmission Served | Facility City |
|---|---|---|---|---|---|---|
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Commercial Operation | Power Generation in progress | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Construction | Pending IA/Customer Payment | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | System Impact Study | Study Complete | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Construction | Pending IA/Customer Payment | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Pending IA/Customer Payment | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Construction | Under Construction / In Progress | Complete | | Distribution | |
| | Withdrawn | | Complete | | Distribution | |
| | Withdrawn | | Complete | | Distribution | |
| | Withdrawn | | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |
| | Facility Study | Pending Customer Response | Complete | | Distribution | |

| Facility State | Net Metering ? | Interconnection Request Received Date | Queue # Issue Date | FastTrack Study Start Date | FastTrack Study End Date | Supplemental Study Start Date |
|---|---|---|---|---|---|---|
| NC | No | 5/5/2016 | 5/6/2016 | | | |
| NC | No | 5/5/2016 | 5/11/2016 | | | |
| NC | No | 10/4/2015 | 3/2/2016 | | | |
| NC | No | 3/18/2016 | 3/22/2016 | | | |
| NC | No | 6/3/2016 | 6/10/2016 | | | |
| NC | No | 4/22/2016 | 4/26/2016 | | | |
| NC | No | 6/24/2016 | 7/1/2016 | | | |
| NC | No | 5/4/2016 | 5/6/2016 | | | |
| NC | No | 6/3/2016 | 7/26/2016 | | | |
| NC | No | 8/10/2016 | 8/11/2016 | | | |
| NC | No | 8/10/2016 | 8/12/2016 | | | |
| NC | No | 8/18/2016 | 8/24/2016 | | | |
| NC | No | 6/20/2016 | 6/22/2016 | | | |
| NC | No | 6/27/2016 | 6/29/2016 | | | |
| NC | No | 9/7/2016 | 9/9/2016 | | | |
| NC | No | 9/28/2016 | 10/3/2016 | | | |
| NC | No | 10/14/2016 | 10/17/2016 | | | |
| NC | No | 11/7/2016 | 11/16/2016 | | | |
| NC | No | 7/10/2016 | 7/13/2016 | | | |
| NC | No | 6/29/2016 | 7/15/2016 | | | |
| NC | No | 11/7/2016 | 11/16/2016 | | | |
| NC | No | 7/9/2016 | 7/26/2016 | | | |
| NC | No | 4/5/2017 | 4/10/2017 | | | |
| NC | No | 8/10/2017 | 8/26/2017 | 8/30/2017 | 8/31/2017 | |
| NC | No | 5/11/2016 | 5/24/2016 | | | |
| NC | No | 8/5/2016 | 8/12/2016 | | | |
| NC | No | 5/4/2016 | 5/27/2016 | | | |
| NC | No | 6/28/2016 | 6/29/2016 | | | |
| NC | No | 8/18/2016 | 8/24/2016 | | | |
| NC | No | 6/29/2016 | 7/12/2016 | | | |
| NC | No | 8/22/2016 | 8/25/2016 | | | |
| NC | No | 5/26/2016 | 7/25/2016 | | | |
| NC | No | 8/10/2016 | 8/30/2016 | | | |
| NC | No | 8/10/2016 | 8/11/2016 | | | |
| NC | No | 9/29/2016 | 10/4/2016 | | | |
| NC | No | 9/7/2016 | 9/15/2016 | | | |
| NC | No | 10/9/2016 | 10/17/2016 | | | |
| NC | No | 9/14/2016 | 9/21/2016 | | | |
| NC | No | 10/9/2016 | 10/17/2016 | | | |
| NC | No | 3/28/2017 | 4/7/2017 | | | |
| NC | No | 5/8/2017 | 5/11/2017 | | | |
| NC | No | 8/9/2017 | 8/19/2017 | 8/25/2017 | 9/21/2017 | 10/13/2017 |
| NC | No | 1/14/2016 | 1/14/2016 | | | |
| NC | No | 2/5/2016 | 2/10/2016 | | | |
| NC | No | 3/31/2016 | 4/6/2016 | | | |
| NC | No | 10/21/2016 | 10/24/2016 | | | |
| NC | No | 10/19/2016 | 11/1/2016 | | | |
| NC | No | 11/4/2016 | 11/7/2016 | | | |
| NC | No | 11/4/2016 | 11/8/2016 | | | |
| NC | No | 6/24/2016 | 7/1/2016 | | | |
| NC | No | 8/10/2016 | 8/12/2016 | | | |
| NC | No | 8/22/2016 | 8/25/2016 | | | |
| NC | No | 8/19/2016 | 9/2/2016 | | | |
| NC | No | 9/15/2016 | 9/16/2016 | | | |
| NC | No | 8/22/2016 | 9/22/2016 | | | |
| NC | No | 10/12/2016 | 10/17/2016 | | | |
| NC | No | 10/28/2016 | 11/8/2016 | | | |
| NC | No | 6/19/2017 | 7/18/2017 | | | |

| Supplemental Study End Date | System Impact Study Start Date | System Impact Study End Date | Facility Study Start Date | Facility Study End Date | IA Sent Date | IA Returned Date | IA Executed Date |
|---|---|---|---|---|---|---|---|
| | 5/9/2016 | 5/10/2018 | 6/20/2018 | | | | |
| | 6/13/2016 | 10/3/2017 | 12/22/2017 | | | | |
| | 4/28/2016 | 8/3/2017 | 11/20/2017 | 1/17/2018 | 1/17/2018 | 1/23/2018 | 1/23/2018 |
| | 5/3/2016 | 9/18/2017 | 10/31/2017 | 1/2/2018 | 1/2/2018 | 1/15/2018 | 1/15/2018 |
| | 6/27/2016 | 7/10/2018 | 7/31/2018 | | | | |
| | 9/27/2016 | 10/12/2017 | | | | | |
| | 11/8/2016 | 7/11/2018 | 7/31/2018 | | | | |
| | 6/14/2016 | 6/18/2018 | | | | | |
| | 11/28/2017 | 9/20/2018 | 10/2/2018 | | | | |
| | 4/12/2017 | 12/4/2017 | 5/7/2018 | | 10/2/2018 | 10/17/2018 | 10/18/2018 |
| | 12/8/2016 | 7/18/2018 | 7/31/2018 | | | | |
| | 1/9/2017 | 7/3/2018 | 10/2/2018 | | | | |
| | 9/12/2016 | 10/2/2017 | 10/25/2017 | 1/25/2018 | 2/8/2018 | 2/22/2018 | 2/24/2018 |
| | 3/3/2017 | 7/11/2017 | 2/20/2018 | 3/13/2018 | 3/13/2018 | 3/19/2018 | 3/19/2018 |
| | 12/8/2016 | 8/20/2018 | 10/17/2018 | | | | |
| | 1/11/2017 | 10/26/2017 | 1/2/2018 | | 10/2/2018 | 10/17/2018 | |
| | 9/11/2017 | 7/6/2018 | 8/9/2018 | | | | |
| | 11/17/2016 | 2/8/2018 | 3/23/2018 | | | | |
| | 9/20/2016 | 10/30/2017 | 11/10/2017 | 10/5/2018 | 10/5/2018 | 10/16/2018 | |
| | 11/17/2016 | 5/16/2018 | 5/25/2018 | 7/6/2018 | 7/6/2018 | 7/11/2018 | 7/12/2018 |
| | 7/14/2017 | 8/16/2018 | 8/31/2018 | | | | |
| | 7/7/2017 | 5/15/2018 | 5/25/2018 | 7/18/2018 | 7/18/2018 | 7/20/2018 | 7/20/2018 |
| | 10/30/2017 | 6/14/2018 | 7/24/2018 | | | | |
| | 1/12/2018 | 7/2/2018 | 9/24/2018 | | | | |
| | 9/13/2017 | 6/7/2018 | | | | | |
| | 6/6/2017 | 5/15/2018 | 5/25/2018 | 10/10/2018 | 10/10/2018 | 10/16/2018 | |
| | 9/13/2017 | 9/12/2018 | | | | | |
| | 11/4/2016 | 7/27/2018 | | | | | |
| | 5/3/2017 | 3/14/2018 | 5/25/2018 | 7/31/2018 | 7/31/2018 | 8/1/2018 | 8/17/2018 |
| | 12/6/2016 | 7/27/2018 | | | | | |
| | 10/16/2017 | 6/21/2018 | 6/27/2018 | 8/14/2018 | 8/14/2018 | 8/21/2018 | 8/22/2018 |
| | 7/10/2017 | 6/7/2018 | | | | 7/25/2016 | |
| | 10/20/2016 | 5/21/2018 | 6/4/2018 | 7/6/2018 | 7/6/2018 | 7/11/2018 | 7/12/2018 |
| | 12/7/2016 | 9/19/2018 | | | | | |
| | 11/16/2016 | 10/2/2018 | | | | | |
| | 10/4/2016 | 9/15/2017 | 12/13/2017 | 6/6/2018 | 6/6/2018 | 6/15/2018 | 6/19/2018 |
| | 8/31/2017 | 5/25/2018 | | | 10/18/2018 | | |
| | 10/7/2016 | 3/6/2018 | 3/15/2018 | 5/16/2018 | 5/16/2018 | 5/25/2018 | 5/31/2018 |
| | 7/25/2017 | 8/27/2018 | | | | | |
| | 8/2/2018 | 8/29/2018 | | | | | |
| | 8/24/2017 | 6/13/2018 | | | | | |
| 1/9/2018 | 5/24/2018 | 10/9/2018 | | | | | |
| | 4/26/2016 | 9/28/2018 | | | | | |
| | 6/6/2016 | 9/14/2018 | | | | | |
| | 5/4/2016 | 8/16/2017 | 8/25/2017 | | | | |
| | 11/16/2016 | 5/16/2018 | 5/25/2018 | 7/19/2018 | 7/19/2018 | 7/30/2018 | 7/30/2018 |
| | 1/11/2017 | 1/11/2017 | | | | | |
| | 1/12/2017 | 1/12/2017 | | | | | |
| | 11/10/2016 | 9/11/2017 | 10/31/2017 | 2/20/2018 | 2/20/2018 | 3/6/2018 | 3/7/2018 |
| | 1/29/2018 | 9/21/2018 | | | | | |
| | 12/7/2016 | 6/12/2018 | | | | | |
| | 11/15/2016 | 6/1/2018 | | | | | |
| | 11/15/2016 | 9/28/2018 | | | | | |
| | 1/15/2018 | 9/13/2018 | | | | | |
| | 10/6/2016 | 8/23/2018 | | | | | |
| | 2/28/2018 | 8/13/2018 | | | | | |
| | 12/7/2016 | 5/15/2018 | | | | | |
| | 8/22/2017 | 6/14/2018 | | | | | |

| Operational Date | C | D,E | F | G,H,I | J | K | L | M | N |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| 8/28/2018 | | | | | | 433 | 1 | 478 | |
| | | | | | | 420 | 1 | 458 | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | 551 | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 345 | 11 | 421 | |
| | | | | | | 258 | 1 | 432 | |
| | | | | | | | | | Yes |
| | | | | | | | | | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 516 | 1 | | |
| | | | | | | 412 | 1 | 502 | |
| | | | | | | | | | Yes |
| | | | | | | 259 | 1 | 501 | |
| | | | | | | | | | Yes |
| | 4 | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 339 | 1 | | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 313 | 1 | 500 | |
| | | | | | | | | | Yes |
| | | | | | | 209 | 1 | 502 | |
| | | | | | | | | | Yes |
| | | | | | | 431 | 1 | 470 | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 421 | 1 | 443 | |
| | | | | | | | | | |
| | | | | | | 404 | 1 | 426 | |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | 23 | | 59 | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | 422 | 1 | 445 | |
| | | | | | | | | | x |
| | | | | | | | | | x |
| | | | | | | 320 | 1 | 333 | x |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |
| | | | | | | | | | Yes |

| #2 | if queue # issued date > Jan 1,2016 | If IA Executed date > Jan 1, 2018 or no IA was sent for c,f,k,n | Comment | Mean | Median | Shortest | Longest | Total | Sample Size | Text |
|---|---|---|---|---|---|---|---|---|---|---|
| C | Queue issue Date | FT end | | 40 | 20 | 2 | 213 | X | 127 | Sample Size: 127 |
| D | FT end | IA Sent | No SIS | 3 | 3 | 3 | 3 | X | 1 | Sample Size: 1 |
| E | FT End | IA Sent | | 3 | 3 | 3 | 3 | X | 1 | Sample Size: 1 |
| F | Supp Review Start | Supp Review End | | 38 | 20 | 1 | 233 | X | 57 | Sample Size: 57 |
| G | Supp Review End | IA Sent | No SIS | 22 | 13 | 2 | 172 | X | 34 | Sample Size: 34 |
| H | Supp Review End | IA Sent | No SIS | 22 | 13 | 2 | 172 | X | 34 | Sample Size: 34 |
| I | Supp Review End | IA Sent | No SIS | 22 | 13 | 2 | 172 | X | 34 | Sample Size: 34 |
| J | Queue issue Date | IA Executed | No SIS | 90 | 77 | 33 | 387 | X | 25 | Sample Size: 25 |
| K | SIS Start | Facility End | No FT/Supp | 367 | 404 | 209 | 516 | X | 15 | Sample Size: 15 |
| L | Facility End | IA Sent | | 2 | 1 | 1 | 11 | X | 15 | Sample Size: 15 |
| M | Queue issue Date | IA Executed | No FT/Supp | 462 | 464 | 333 | 551 | X | 14 | Sample Size: 14 |
| N | Have Queue date | no IA sent | Count of # | X | X | X | X | 209 | | |

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide the following information related to interconnection screens.

a. For the data regarding Fast Track screen passage results provided by Duke during the stakeholder process, please identify whether this data included projects proceeding through the 20 kW small inverter process (section 2.0).
b. If it did not, please provide statistics for screen passage rates for the 20 kW small inverter based process across Duke's territory for the last three years.
c. Please provide an updated version of the Fast Track and Supplemental Review statistics that contains data for the last three years.
d. Describe how Duke determines whether a project will cause any device or equipment to exceed 87.5% of the short circuit interrupting capability in Fast Track Screen 3.2.1.7.
e. If a project fails Screen 3.2.1.7 and proceeds to Supplemental Review, describe how Duke determines whether the project may interconnect safely and reliably.
f. If a project fails Screen 3.2.1.2 and proceeds to Supplemental Review, describe how Duke determines whether the project may interconnect safely and reliably.
g. Explain what other studies or screens Duke applies during Supplemental Review to determine whether a proposed project can be interconnected safely and reliably.

**Corrected Response:**

**Duke Response 1-3a.**

a. The data provided by Duke during the stakeholder process did not include projects proceeding through the expedited Section 2 $\leq$ 20 kW study process (section 2.0).

**Duke Response 1-3b.**

b. Duke Energy are uses demand tables screening process to assess potential impacts of < 20 kW systems and does not track data on Fast Track screen passage rates. If a customer has submitted an application, and system size is too large, the Renewables Service Center will provide guidance to the customer as to the appropriate size system that is best suited for that location. This guidance is provided in writing and is located on the 10 Day Letter to the customer.

**Corrected Duke Response 1-3c.**

c. An updated version of the data provided is not readily available and would require a significant amount of manual effort; that data was originally provided by manually tallying email correspondences of Fast Track and Supplemental Review results. However, we extracted the following from the SalesForce database by looking for projects with dates for Fast Track and Supplemental Review [Study] Start and End dates. The data below only refers to Fast Track, there are only rare instances when a project is offered Supplemental Review that does not pass:

DEC NC

| Fast Track Results Per Size | | | |
|---|---|---|---|
| kW | Fail | Pass | Fail % |
| 20-100 | 71 | 1 | 98.6% |
| 100-500 | 35 | 0 | 100.0% |
| 500-1000 | 26 | 2 | 92.3% |
| >1000 | 13 | 0 | 100.0% |
| **Total** | 145 | 3 | 97.9% |

May 2015 - October 2018

DEP NC

| Fast Track Results Per Size | | | |
|---|---|---|---|
| kW | Fail | Pass | Fail % |
| 20-100 | 40 | 2 | 95.0% |
| 100-500 | 27 | 0 | 100.0% |
| 500-1000 | 29 | 0 | 100.0% |
| >1000 | 13 | 0 | 100.0% |
| **Total** | 109 | 2 | 98.2% |

May 2015 - October 2018

Duke Energy DEC

| Supplemental Review Results | | | |
|---|---|---|---|
| | Fail | Pass | Fail % |
| **Total** | 1 | 89 | 1.1% |

May 2015 - October 2018

Duke Energy DEP

| Supplemental Review Results | | | |
|---|---|---|---|
| | Fail | Pass | Fail % |
| **Total** | 2 | 62 | 3.2% |

May 2015 - October 2018

**Duke Response 1-3d.**

d. For Net-Metering/Secondary Connections and Primary Sell All Fast Track generating facility Interconnection Requests, Duke Energy does not study whether a project will cause a device to exceed 87.5% of the short circuit interrupting capability within the initial Fast Track screening process. During the initial Fast Track screening process Duke Energy references devices that exist at or above 87.5% of their interrupting rating without the addition of the Interconnection Facility. This is because Screen 3.2.1.7 of the NC Interconnection Procedures states "nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability" and devices are typically used on the distribution system up to 100% of their interrupting ratings. Since Fast Track eligible projects are limited to below 2 MW and the fault contribution of the solar sites is generally studied at 125% of nameplate AC output, for a 5 kV connected 2 MW site they would contribute less than 300 Amps to the circuit fault current which should not cause any device to exceed 100% if it is currently below the 87.5% value prior to the addition of the Generating Facility's inverters.

Additionally, a more rigorous short circuit analysis is included in Supplemental Review as described in the response to 3e.

**Duke Response 1-3e.**

e. Within the Supplemental Review process, if a project failed the Initial Review Screen 3.2.1.7, Duke Energy performs additional circuit analysis that takes into account the fault contribution of the Generating Facility to the distribution system. The distribution protective devices are then re-evaluated to determine if the additional fault contribution will cause the available fault current at these devices to exceed their interrupting ratings. In the event that the additional fault contribution from the Generating Facility causes a device's interrupting rating to be exceeded, the Generating Facility is deemed to not be able to interconnect safely and reliably, and therefore must proceed to the System Impact Study for further review.

Additionally, for Generating Facilities co-located with load, the service transformer protective device is reviewed to determine if the fault contribution from the Generating Facility has the possibility of operating this device, which would cause an outage for the retail customer(s) located on the secondary (LV) side of the transformer when the utility (MV) side is restored.

**Duke Response 1-3f.**

f. Within the Supplemental Review process, if a project failed the Initial Review Screen 3.2.1.2, Duke Energy performs additional circuit analyses to evaluate if the addition of the Generating Facility violates voltage and/or thermal overload limitations. These evaluations include, but are not limited to: (a) daytime valley loading data modeling to determine if the power output from the Generating Facility, in aggregation with other Generating Facilities queued and/or connected ahead, will cause any voltage regulators to experience reverse power flow since controls equipped with co-generation capabilities are needed in order to properly regulate voltage during reverse power flow; (b) calculation of the Rapid Voltage Change (RVC) that may be experienced by Duke Energy retail customer(s) with the addition of the Generating Facility to ensure that the results are within the RVC & Flicker Study Criteria limitations; (c) evaluation of the Duke Energy service voltages with the addition of the Generating Facility to ensure that the voltages are within the limitations set by ANSI C84.1; and, (d) evaluation of the capacities of the Generating Facility, in aggregation with other Generating Facilities queued and/or connected ahead, to determine if the sum cannot exceed 10% of the substation transformer top-end rating for DEP, and 10% of the low-end/nominal rating for DEC. A failure of any of these evaluations deems that the Generating Facility cannot interconnect safely and reliably, and therefore must proceed to the System Impact Study for further review.

**Duke Response 1-3g.**

g. *Net-Metering/Secondary Connections:* For projects that are secondary connections, Duke Energy evaluates three additional screens during Supplemental Review. The first screen measures voltage rise and power backflow during valley loading conditions. The second screen is for service transformer protection, delivery side flicker, and winding configurations. The last screen involves comparison of substation capacity to the amount of existing and queued secondary connection generation on the feeder/substation bus.

*Primary Sell All:* For projects that are primary connected utility scale generators, Duke Energy evaluates two additional screens during Supplemental Review. The first is a measurement of the voltage and flicker limits across the distribution system in relation to transformer inrush. A protection review is also completed to insure device coordination and set points of all upstream protective equipment.

Interstate Renewable Energy Council
Data Request No. 1
Docket No. E-100, Sub 101
NCIP
Item No. 1-4

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

Please provide the following information related to interconnection transparency.

a. Has Duke investigated developing Hosting Capacity Maps, or similar informational systems?
    i. If yes, list and describe the Hosting Capacity methods or similar informational systems Duke looked into as part of its investigation into developing Hosting Capacity Maps.
    ii. If yes, please provide any reports, studies and/or data on what Duke expects it to cost to develop Hosting Capacity Maps, or similar information systems.
b. Has Duke identified any technical or data barriers for the development of a Hosting Capacity Map in Duke's territory? If so, please describe.
c. What information will be provided to customers with the "grid locational guidance" that Duke is currently developing?
d. Will the "grid locational guidance" be available to any interconnection customer, or only to projects bidding into the CPRE?
e. Has Duke investigated the cost of developing an online portal for all interconnection customers?
    i. If so, provide data on what Duke expects it to cost to develop an online portal for interconnection customers.
f. Identify which data points recommended by IREC for inclusion in the pubic queue, as described in proposed section 1.5 of the Working Group Recommendations Redline of North Carolina Interconnection Procedures, N.C.U.C. Docket No. E-100, Sub 101 (Dec. 15, 2017) are not currently tracked by Duke.
g. Please provide a redacted (to remove any Confidential Business Information) example of a study report for the following studies, which Duke has provided to an Interconnection Customer:
    i. Fast Track
    ii. Supplemental Review
    iii. System Impact Study
    iv. Facilities Study

<u>Response</u>:

**Duke Response 1-4a.**

a. See Duke's response to Public Staff Data Request No. 5, Items 5-2, 5-4, and 5-5 in response to this request.

**Duke Response 1-4b.**

b. See Duke's response to Public Staff Data Request No. 5, Items 5-2, 5-4, and 5-5 in response to this request.

**Duke Response 1-4c.**

c. The document titled "DEP and DEC Generate Interconnection Requirements and Locational Guidance 5-9-201 FINAL.pdf" provided below includes a narrative that explains the process used for creating the grid locational guidance for DEP and DEC. This document also includes a map showing the areas with known transmission constraints, the document labeled "DEC DEP Constraint Map.pdf" also provided below. A separate document lists the lines and substations inside the contained areas, the "DEC/DEP Lines and Subs Constrained Infrastructure.pdf" document provided below. Collectively, these documents detail the information customers will be provided for grid locational guidance, and are available on DEC's and DEP's OASIS websites.

PDF PDF PDF

DEP-DEC Gen(DEP Lines an(DEC Lines an(

**Duke Response 1-4d.**

d. The "Grid Locational Guidance" is publicly available on OASIS websites for DEC and DEP under the folder labeled "Generator Interconnection Information," and is therefore available to all Interconnection Customers.

**Duke Response 1-4e.**

e. Duke Energy is currently developing a record system through Salesforce to store all interconnection-related data in all regulated jurisdictions. One important portion of the record system development is an online portal that will enable interconnection customers to login and view their specific projects, enter all interconnection-related application data, allow for electronic signatures and printouts that mimic the NCIP-required forms, make electronic payments of fees and deposits, and monitor status of projects. The cost to develop this online portal portion of the record system is not tracked separately from the other Salesforce-related project work, as much of the project work is interdependent to creating the record system as a whole (*i.e.* building out the data fields in Salesforce to be able to capture and track data according to the process steps outlined in the NCIP). DEC and DEP expect the North Carolina-allocated expenses to approximate $700,000 on Salesforce project work in 2018, with a similar amount expected to be spent in 2019. The first stage of the interconnection online portal for NC and SC large distribution interconnection customers is planned to be complete prior to the end of 2018.

**Duke Response 1-4f.**

As of October 2018, the Companies are now tracking the following data points:

1. Application and/or Queue Number
    a. The equivalent of the "Checklist ID" and "Queue Number" as recommended by IREC
2. Facility Capacity (kW)
    a. The equivalent of "Installed Capacity kW AC" as recommended by IREC
3. Primary Fuel Type (e.g. solar, wind, bio-gas, etc.)
    a. The equivalent of "Energy Source Type" and "Prime Mover" as recommended by IREC
4. Exporting or Non-Exporting
    a. The equivalent of "Net Metering" or "Purchase Power," "PPA type," "Net Meter Rider," or "Rate Schedule Customer Type" as recommended by IREC
5. City
    a. The equivalent of "Facility City" as recommended by IREC
6. Zip Code
    a. The equivalent of "Facility Zip Code" as recommended by IREC
7. Substation
    a. The equivalent of "Substation Name" as recommended by IREC
8. Feeder
    a. The equivalent of "Feeder Number" as recommended by IREC
9. Status (active, withdrawn, interconnected, etc.)
    a. The equivalent of "Operational Status" as recommended by IREC
10. Date Application Deemed Complete
    a. The equivalent of "Queue Issued Date" as recommended by IREC
11. Date of Notification of Fast Track Screen Results (including 20 kW Inverter Process projects) (if applicable)
    a. The equivalent of "Fast Track Study End Date" as recommended by IREC
12. Date of Notification of Supplemental Review Results (if applicable)
    a. The equivalent of "Supplemental Study End Date" as recommended by IREC
13. Date of Notification of Impact Study results (if applicable)
    a. The equivalent of "System Impact Study End Date" as recommended by IREC
14. Date of Notification of Facilities Study Results and/or Construction Estimates (if applicable)
    a. The equivalent of "Facility Study End Date" as recommended by IREC
15. Date Final Interconnection Agreement is Provided to Customer
    a. The equivalent of "IA Return Date (Customer signed/returned)" and "IA Execution Date (when co-signed/returned)" as recommended by IREC

The following is a list of items recommended by IREC that the Companies currently do not track:

1. Secondary fuel type (if applicable)
2. Fast Track Screen Results (pass or fail, and if fail, identify the screens failed)
    a. However, these are captured within the Fast Track page
3. Supplemental Review Results (pass or fail, and if fail identify the screens failed)
    a. The Companies currently use dates and project status to interpret the Supplemental Review Results, as opposed to having a field for "Supplemental Review Pass" or "Supplemental Review Fail"
4. Date of grant of permission to operate
    a. DEC and DEP do not use "Operational Date" consistently; instead, DEC uses the field to capture Initial Delivery while DEP uses the field to capture PTO
5. Final interconnection cost paid to utility

**Duke Response 1-4g.**

f.

i. Please refer to the attachments labeled "Fast Track" and "Fast Track and Supplemental Examples.pdf" provided below.

ii. Please refer to the attachment labeled "Fast Track and Supplemental Examples.pdf" provided below.

iii. Please refer to the attachment labeled "Facility Study Example.pdf" provided below.

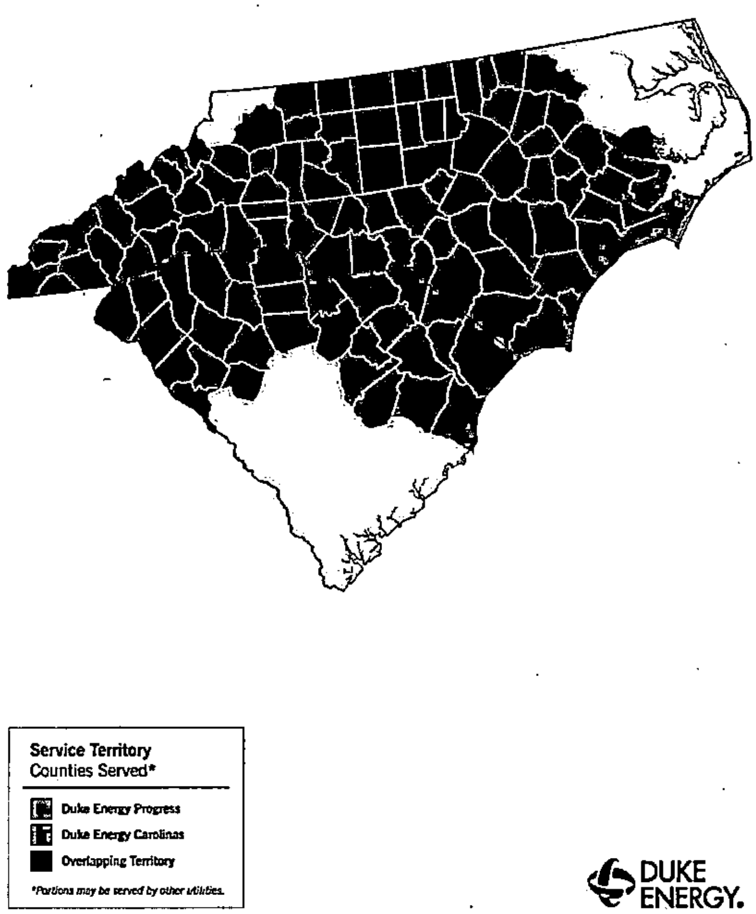
iv. Please refer to the attachment labeled "Anonymized NC System Impact Study Report.pdf" provided below.

Fast Track.ı Fast Track ‹ Facilitv Stu Anonvmizec

## Overview

Duke Energy offers energy services to approximately 7.4 million customers in the Carolinas, Florida, Ohio, Kentucky and Indiana. The Carolinas area is comprised of Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP). The DEC service territory is approximately 24,000 square miles and serves 2.5 million residential, commercial and industrial customers. Primary transmission voltages in DEC are 500kV, 230kV, 161kV, 100kV, 66kV, and 44kV. The DEP service territory is approximately 32,000 square miles and serves 1.5 million residential, commercial and industrial customers. Primary transmission voltages in DEP are 500kV, 230kV, and 115kV.

Carolinas Service Territory




DUKE ENERGY.

## Planning the Transmission System

The analysis performed by Duke Energy in planning the transmission system is based on good utility practice and NERC Reliability Standards. The analysis is performed to ensure reliable service can be provided to all customers considering that outage events (lightning, car accidents, equipment failure, faults, etc.) that cause transmission and generation elements to be removed from service can and do occur. Outage events can impact the voltage levels and the power flows on the transmission system in ways that would stress the system beyond its capabilities if the system were not properly planned, resulting in customer outages or poor power quality. Addition of new transmission and distribution connected load and generation requires ongoing analysis to ensure continued operation within limits. When analysis indicates limits will be exceeded, modifications or upgrades to the system must be identified to ensure continued reliable operation. The decisions to upgrade or modify system elements are made by applying reliability standards on an equivalent basis to all interconnection requests, and selected solutions to system issues are identified to minimize costs to the total body of Duke Energy customers.

When a new generation project requests transmission interconnection, Duke Energy is required to assess the impact of the new generation on the electric system. The assessment identifies locations where modification or upgrade of the transmission system will be necessary to maintain reliable service to all interconnected electricity customers, including consideration of possible outage events. The assessment includes the impacts of distribution-interconnected generation projects, which also affect transmission system loadings.

As a result of analyses performed to date, Duke Energy has identified areas where modification and upgrade of the system would be required if generator projects in the queue were to be interconnected. The areas where proposed projects have already indicated a need for transmission upgrades are identified on the constrained area maps. In other words, projects already under consideration, located in constrained areas, have resulted in demands exceeding the transmission grid capability and, if they are pursued to commercial operation, will require additional transmission capacity. Any new or additional transmission or distribution interconnection requests submitted in these constrained areas, after those currently in the queue for analysis, will possibly contribute to additional upgrade needs that may add project costs.

The need for transmission system upgrades is subject to the final disposition of the individual projects, i.e., whether or not they are pursued to commercial operation. Thus the need for transmission system upgrades can be subject to change as additional projects are analyzed or individual projects decide not to continue with the interconnection process. Therefore, the identification of constrained areas should be considered a snapshot based on conditions known at the time. However, developers of potential projects in the identified constrained areas should be aware that there is a risk of additional transmission grid upgrades, which could result in additional costs and lead time requirements for the project. This would include distribution interconnected projects, which also impact transmission system loadings.

## DEC Generator Interconnection Requirements - Overview

Transmission level projects participating in the DEC CPRE are likely to interconnect to either the 100 or 44 kV system. Unless a project is interconnecting directly to an existing 100 kV station, the project will interconnect via a tap to a single 100 or 44 kV transmission circuit. For 100 kV projects tapping a single circuit, this design will typically include a three-way gang operated air break switch in line with the main line and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For 44 kV projects tapping a single circuit, this design will typically include a 4-pole bent in line with the main line, disconnect switches, and a breaker (or circuit switcher) on the tap line at the point of change in ownership. For both 100 kV and 44 kV projects, the design will include a transfer trip scheme for faults anywhere on the main or tap line.

Transmission level projects participating in the CPRE may be permitted to interconnect directly to an existing 230 kV station. Any 230 kV interconnections not directly into an existing station require the generation aggregated at a new station to exceed 120 MW.

For additional details, refer to the DEC Facility Connection Requirements located under Generator Interconnection Information at the DEC OASIS website[1].

## Constrained Areas in DEC

For DEC, the constrained area map (Attachment 1) represents areas of the transmission system where there are either known transmission constraints that would be aggravated by increased generation or transmission constraints that are created by queued generation. These transmission constraints have been identified by either Transmission Planning or System Operations and have been confirmed through transmission studies of one or more generator interconnection requests. Transmission upgrades to mitigate the constraints already identified would exceed $10 million, and lead time is dependent upon the scope of work but would exceed 1 year, and possibly be as long as 3-4 years. Generator interconnection requests in areas not identified as constrained may also require transmission upgrades, but transmission studies are required in order to make this determination.

There are three constrained areas identified in DEC. In Guilford and Rockingham counties, off-peak conditions can drive post-contingency thermal loading issues on 100 kV lines that emanate from Dan River. Increased generation in these two counties will make the 100 kV lines in the Dan River area more susceptible to both off-peak and on-peak loading issues. The other two constrained areas shown are areas on DEC's system with the highest penetration of queued solar generation. The six county area near DEC's southern border including Newberry, Laurens, Greenwood, Abbeville and portions of Greenville and Anderson counties has over 1600 MW of queued solar generation. The other is a three county area located near the DEC/DEP border including Chester, Lancaster and Union (NC) counties that has over 600 MW of queued solar generation.

[1] https://www.oasis.oati.com/duk/index.html

A DEC constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained areas.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[2].

## DEP Generator Interconnection Requirements - Overview

To connect to the DEP 230 or 115 kV transmission system, a generating plant should be at least 20 MW in size. Plants between 20 and 100 MW will typically be tapped off a 230 or 115 kV transmission line. This design will typically include line switches added to the main line on either side of the tap, a single radial breaker in the tap line, and a transfer trip scheme for faults anywhere on the main or tap line. DEP will typically build and own the transmission tap line and the breaker station adjacent to the generator substation. To connect to the DEP 500 kV system, a generating plant must be at least 500 MW.

If the total generation at a single site (or within a one mile radius) exceeds 100 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required. If the total tapped generation along an entire line exceeds 200 MW, then a full transmission switching station (e.g. a three-breaker ring bus) will be required somewhere on the line (location to be determined on a case-by-case basis considering specific local conditions). If a generating plant connects to a DEP switching station, the generator owner will typically build and own the radial transmission line from the generating plant to the DEP switching station.

For additional details, refer to the DEP Facility Connection Requirements located under Generator Interconnection Information at the DEP OASIS website[3].

## Constrained Areas in DEP

For DEP, the constrained area map (Attachment 1) represents areas of the DEP transmission system where additional generator interconnections have a high likelihood (depending on ultimate development decisions) of causing transmission problems requiring significant, expensive, and long-lead-time transmission upgrades. The constrained areas were determined by Transmission Planning from prior studies and knowledge of the DEP transmission system. Generator interconnections in regions that are not identified as constrained are not guaranteed to be without transmission problems. Studies will determine if there are any issues requiring transmission upgrades caused by generator interconnection requests in areas not identified as constrained.

In the greater Cumberland and Richmond County regions of North Carolina, extending across the state line into much of DEP's service territory in South Carolina, significant solar generation additions in the 2014-2017 timeframe, on both the transmission and distribution systems, have loaded the DEP

[2] https://ezmt.anl.gov/
[3] https://www.oasis.oati.com/cpl/index.html

transmission system to its limits. Any new generation in this area will cause transmission line overloads. Identified solutions exceed $100 million in transmission upgrades and would take at least 4 years to complete.

In the greater Brunswick County region of North Carolina, existing limits on the transmission system can cause limitations in operation of the Brunswick nuclear generators. These thermal and dynamic stability limitations require that the output of the Brunswick nuclear generators be substantially reduced following the outage of any one transmission line in the area. This includes forced outages or planned maintenance outages of transmission lines in the Brunswick County region. Any additional generation in this region would cause additional, unacceptable limitations in operation of the Brunswick nuclear generators without the addition of costly transmission solutions. The estimated cost of the identified transmission solution for this issue exceeds $100 million and would take at least 5 years to complete.

A DEP constrained infrastructure list is available that documents the individual transmission lines and substations that are in the constrained area.

Additional transmission line mapping information can be found at the Energy Zones Mapping Tool website[4].

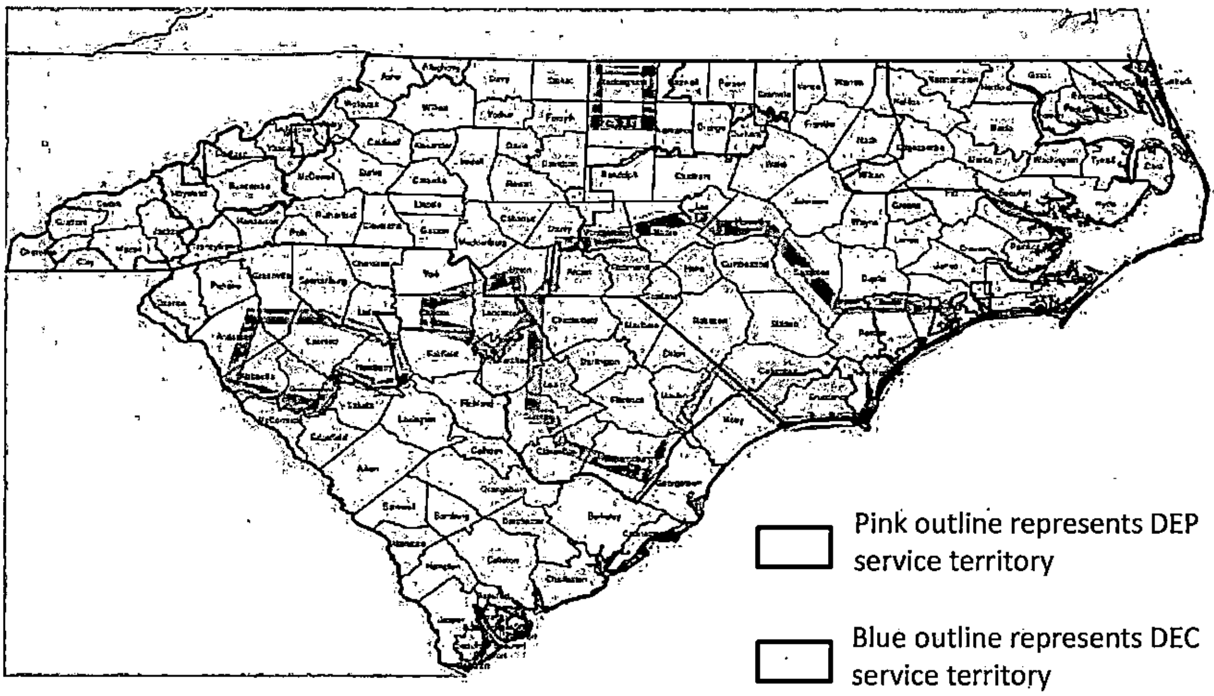
## Connecting Smaller Generators to the DEC and DEP Distribution Systems

Guidelines for the connection of smaller generators to the DEC and DEP Distribution Systems are provided in the Duke Energy Method of Service Guidelines[5]. In general, projects between 10 and 20 MW may be able to connect directly to a retail substation depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines. Projects less than 10 MW may be able to connect to a general distribution circuit depending the voltage class of the distribution circuit, the voltage class of the transmission line serving the retail station, and other specific local factors described in the guidelines.

[4] https://ezmt.anl.gov/
[5] https://www.duke-energy.com/home/products/renewable-energy/generate-your-own

Attachment 1

DEC and DEP Constrained Areas



Pink outline represents DEP service territory

Blue outline represents DEC service territory

# DEP Constrained Infrastructure

| Line Name | kV | Substation | Type |
|---|---|---|---|
| Barnard Creek - Carolina Beach 115kV Feeder | 115 | Carolina Beach | T-D |
| Barnard Creek - Carolina Beach 115kV Feeder | 115 | Wilmington River Road | T-D |
| Barnard Creek - Town Creek Overhead 230kV | 230 | - | - |
| Barnard Creek - Town Creek UG 230kV | 230 | - | - |
| Barnard Creek - Wilmington Corning SS 230kV | 230 | Wilmington Cedar Ave | T-D |
| Barnard Creek - Wilmington Corning SS 230kV | 230 | Wilmington Corning | T-D |
| Barnard Creek - Wilmington Corning SS 230kV | 230 | Wilmington Winter Park | T-D |
| Barnard Creek - Wilmington Sunset Park 115kV Feeder | 115 | Wilmington Sunset Park | T-D |
| Bennettsville SS - Laurinburg 230kV | 230 | McColl | T-D |
| Biscoe - Rockingham 230kV | 230 | Rockingham Aberdeen Rd | T-D |
| Blewett Falls Plant - Rockingham 115kV | 115 | Rockingham West | T-D |
| Blewett Falls Plant - Tillery Plant 115kV | 115 | - | - |
| Brunswick Plant Unit 1 - Castle Hayne 230kV East | 230 | Brunwsick EMC Daws Creek POD | POD |
| Brunswick Plant Unit 1 - Castle Hayne 230kV East | 230 | Masonboro | T-D |
| Brunswick Plant Unit 1 - Castle Hayne 230kV East | 230 | Wilmington Ogden | T-D |
| Brunswick Plant Unit 1 - Castle Hayne 230kV East | 230 | Wrightsville Beach | T-D |
| Brunswick Plant Unit 1 - Delco 230kV East | 230 | Brunswick EMC Bolivia POD | POD |
| Brunswick Plant Unit 1 - Delco 230kV East | 230 | Southport | T-D |
| Brunswick Plant Unit 1 - Delco 230kV East | 230 | Southport ADM | T-D |
| Brunswick Plant Unit 1 - Delco 230kV East | 230 | Southport Cogentrix | Gen |
| Brunswick Plant Unit 1 - Jacksonville 230kV | 230 | Jones-Onslow EMC Meadowview POD | POD |
| Brunswick Plant Unit 1 - Jacksonville 230kV | 230 | Rocky Point | T-D |
| Brunswick Plant Unit 1 - Weatherspoon Plant 230kV | 230 | - | - |
| Brunswick Plant Unit 2 - Delco 230kV West | 230 | Brunswick EMC Southport POD | POD |
| Brunswick Plant Unit 2 - Town Creek 230kV | 230 | - | - |
| Brunswick Plant Unit 2 - Wallace 230kV | 230 | - | - |
| Brunswick Plant Unit 2 - Whiteville 230kV | 230 | Brunswick EMC Prospect POD | POD |
| Cape Fear Plant - West End 230kV | 230 | Central EMC Center Church POD | POD |
| Cape Fear Plant - West End 230kV | 230 | Sanford Garden St | T-D |
| Cape Fear Plant - West End 230kV | 230 | Sanford Horner Blvd | T-D |
| Cape Fear Plant - West End 230kV | 230 | Sanford US1 | T-D |
| Castle Hayne - Folkstone 115kV | 115 | Holly Ridge | T-D |
| Castle Hayne - Folkstone 115kV | 115 | Jones-Onslow EMC Folkstone POD | POD |
| Castle Hayne - Folkstone 115kV | 115 | Jones-Onslow EMC Hugh Batts POD | POD |
| Castle Hayne - Folkstone 115kV | 115 | Jones-Onslow EMC Morris Landing POD | POD |
| Castle Hayne - Folkstone 115kV | 115 | Jones-Onslow EMC Topsail POD | POD |
| Castle Hayne - Folkstone 115kV | 115 | Vista | T-D |
| Castle Hayne - Wallace 115kV | 115 | Burgaw | T-D |
| Castle Hayne - Wallace 115kV | 115 | Castle Hayne Carolinas Cement | T-D |
| Castle Hayne - Wallace 115kV | 115 | Wilmington Elementis | T-D |
| Castle Hayne - Wilmington Corning SS 230kV | 230 | - | - |
| Clinton - Vander 115kV | 115 | Roseboro | T-D |
| Clinton - Vander 115kV | 115 | South River EMC Roseboro POD | POD |
| Clinton - Vander 115kV | 115 | South River EMC Stedman POD | POD |
| Clinton - Vander 115kV | 115 | Vander DAK | T-D |
| Cumberland - Delco 230kV | 230 | Four County EMC Kelly POD | POD |

# DEP Constrained Infrastructure

| | | | |
|---|---|---|---|
| Cumberland - Delco 230kV | 230 | Four County EMC York POD | POD |
| Cumberland - Delco 230kV | 230 | Garland | T-D |
| Cumberland - Delco 230kV | 230 | Rowan Creek Solar | Gen |
| Cumberland - Delco 230kV | 230 | Turnbull Creek Solar | Gen |
| Cumberland - Fayetteville 230kV North | 230 | - | - |
| Cumberland - Fayetteville 230kV South | 230 | - | - |
| Cumberland - Richmond 500kV | 500 | - | - |
| Cumberland - Wake 500kV | 500 | - | - |
| Cumberland - Whiteville 230kV | 230 | Bladenboro Solar | Gen |
| Cumberland - Whiteville 230kV | 230 | Four County EMC Powell POD | POD |
| Cumberland - Whiteville 230kV | 230 | Four County EMC Tarheel POD | POD |
| Darlington County Plant - Bennettsville SS 230kV | 230 | Bennettsville | T-D |
| Darlington County Plant - Bennettsville SS 230kV | 230 | Society Hill | T-D |
| Darlington County Plant - Florence 230kV | 230 | - | - |
| Darlington County Plant - Robinson Plant 230kV North | 230 | - | - |
| Darlington County Plant - Robinson Plant 230kV South | 230 | - | - |
| Darlington County Plant - SCPSA South Bethune 230kV | 230 | - | - |
| Darlington County Plant - Sumter 230kV | 230 | Bishopville | T-D |
| Darlington County Plant - Sumter 230kV | 230 | Sumter Alice Drive | T-D |
| Darlington County Plant - Sumter 230kV | 230 | Sumter North | T-D |
| Darlington County Plant - Sumter 230kV | 230 | Sumter Wedgefield Road | T-D |
| Delco - Riegelwood Intl Paper 115kV Feeder | 115 | Riegelwood Intl Paper | T-D |
| Delco - Whiteville 115kV | 115 | Brunswick EMC Hallsboro POD | POD |
| Delco - Whiteville 115kV | 115 | Brunswick EMC South Whiteville POD | POD |
| Delco - Whiteville 115kV | 115 | Lake Waccamaw | T-D |
| Delco - Whiteville 115kV | 115 | Whiteville | T-D |
| Erwin - Fayetteville 115kV | 115 | Beard | T-D |
| Erwin - Fayetteville 115kV | 115 | Erwin Mills | T-D |
| Erwin - Fayetteville 115kV | 115 | Fayetteville Slocomb | T-D |
| Erwin - Fayetteville 115kV | 115 | Godwin | T-D |
| Erwin - Fayetteville 115kV | 115 | South River EMC Beard POD | POD |
| Erwin - Fayetteville 115kV | 115 | South River EMC Wade POD | POD |
| Erwin - Fayetteville East 230kV | 230 | Linden | T-D |
| Fayetteville - Fayetteville Dupont SS 115kV | 115 | Fayetteville DuPont | T-D |
| Fayetteville - Fayetteville Dupont SS 115kV | 115 | Hope Mills Church St | T-D |
| Fayetteville - Fayetteville Dupont SS 115kV | 115 | Roslin Solar | Gen |
| Fayetteville - Fayetteville Dupont SS 115kV | 115 | South River EMC Grays Creek POD | POD |
| Fayetteville - Fayetteville East 230kV | 230 | - | - |
| Fayetteville - Ft. Bragg Woodruff St. 230kV | 230 | Clifdale | T-D |
| Fayetteville - Ft. Bragg Woodruff St. 230kV | 230 | Fayetteville PWC Reilly Rd POD | POD |
| Fayetteville - Ft. Bragg Woodruff St. 230kV | 230 | Fort Bragg Knox St | T-D |
| Fayetteville - Ft. Bragg Woodruff St. 230kV | 230 | Fort Bragg Main | T-D |
| Fayetteville - Ft. Bragg Woodruff St. 230kV | 230 | Sandhills Utilities Knox St POD | POD |
| Fayetteville - Raeford 230kV | 230 | Hope Mills Rockfish Rd | T-D |
| Fayetteville - Rockingham 230kV | 230 | Hamlet | T-D |
| Fayetteville - Rockingham 230kV | 230 | Shoe Heel Creek Solar | Gen |
| Fayetteville - Vander 115kV North | 115 | South River EMC Vander POD | POD |

# DEP Constrained Infrastructure

| | | | |
|---|---|---|---|
| Fayetteville - Vander 115kV South | 115 | Vander DAK | T-D |
| Fayetteville East - Ft. Bragg Woodruff St. 230kV | 230 | - | - |
| Florence - Florence Mount Hope 115kV Feeder | 115 | Florence Mt Hope | T-D |
| Florence - Florence Roche Carolinas 115kV | 115 | Florence Mars Bluff | T-D |
| Florence - Kingstree 230kV | 230 | Florence Cashua | T-D |
| Florence - Kingstree 230kV | 230 | Florence Ebenezer | T-D |
| Florence - Kingstree 230kV | 230 | Kingstree North | T-D |
| Florence - Kingstree 230kV | 230 | Lake City | T-D |
| Florence - Kingstree 230kV | 230 | Olanta | T-D |
| Florence - Kingstree 230kV | 230 | Sardis | T-D |
| Florence - Latta 230kV | 230 | - | - |
| Florence - Marion 115kV | 115 | Florence Burch's Crossroads | T-D |
| Florence - Marion 115kV | 115 | Florence General Electric | T-D |
| Florence - Marion 115kV | 115 | Florence Johnson Controls | T-D |
| Florence - Marion 115kV | 115 | Florence L-TEC | T-D |
| Florence - Marion 115kV | 115 | Florence South | T-D |
| Florence - SCPSA Darlington 230kV | 230 | Florence West | T-D |
| Florence Dupont - Florence Roche Carolinas 115kV | 115 | - | - |
| Florence Dupont - Marion 115kV | 115 | Marion Bypass | T-D |
| Florence Dupont - Marion 115kV | 115 | Marion Masonite | T-D |
| Florence Dupont - SCPSA Hemingway 115kV | 115 | Florence Stone Container | T-D |
| Florence Dupont - SCPSA Hemingway 115kV | 115 | Hemingway | T-D |
| Florence Dupont - SCPSA Hemingway 115kV | 115 | Hemingway Tupperware | T-D |
| Florence Dupont - SCPSA Hemingway 115kV | 115 | Pamplico | T-D |
| Florence Dupont - SCPSA Hemingway 115kV | 115 | Pamplico Delta Mills | T-D |
| Folkstone - Jacksonville City 115kV | 115 | Jacksonville Blue Creek | T-D |
| Folkstone - Jacksonville City 115kV | 115 | Jones-Onslow EMC Morton POD | POD |
| Folkstone - Jacksonville City 115kV | 115 | Jones-Onslow EMC Southwest POD | POD |
| Ft. Bragg Woodruff St - Richmond Sub 230kV | 230 | Fort Bragg Longstreet Rd | T-D |
| Ft. Bragg Woodruff St - Richmond Sub 230kV | 230 | Sandhills Utilities Fort Bragg 3rd Brigade POD | POD |
| Ft. Bragg Woodruff St. - Manchester 115kV Feeder | 115 | Central EMC Spout Springs POD | POD |
| Ft. Bragg Woodruff St. - Manchester 115kV Feeder | 115 | South River EMC Eureka Springs POD | POD |
| Ft. Bragg Woodruff St. - Manchester 115kV Feeder | 115 | South River EMC Manchester POD | POD |
| Harris Plant - Ft. Bragg Woodruff St. 230kV | 230 | Central EMC Docs Rd POD | POD |
| Harris Plant - Ft. Bragg Woodruff St. 230kV | 230 | Spring Lake | T-D |
| Kingstree - Andrews 115kV Feeder | 115 | Andrews | T-D |
| Kingstree - Sumter 115kV | 115 | Alcolu Grant | T-D |
| Kingstree - Sumter 115kV | 115 | Manning | T-D |
| Latta - Marion 230kV | 230 | - | - |
| Laurinburg - Libbey Owens Ford 115kV North | 115 | Libbey Owens Ford | T-D |
| Laurinburg - Libbey Owens Ford 115kV North | 115 | Lumbee River EMC Laurinburg POD | POD |
| Laurinburg - Libbey Owens Ford 115kV South | 115 | Libbey Owens Ford | T-D |
| Laurinburg - Raeford 115kV | 115 | Maxton Airport | T-D |
| Laurinburg - Raeford 115kV | 115 | Maxton Solar | Gen |
| Laurinburg - Raeford 115kV | 115 | Wagram JP Stevens | T-D |
| Laurinburg - Richmond 230kV | 230 | Laurel Hill | T-D |
| Laurinburg - Richmond 230kV | 230 | Laurinburg City | T-D |

# DEP Constrained Infrastructure

| | | | |
|---|---|---|---|
| Lilesville - DPC Oakboro 230kV Black and White | 230 | Ansonville | T-D |
| Lilesville - Rockingham 230kV Black and White | 230 | - | - |
| Lilesville - Rockingham 230kV South | 230 | - | - |
| Marion - SCPSA Marion 230kV North | 230 | - | - |
| Marion - SCPSA Marion 230kV South | 230 | - | - |
| Marion - Whiteville 115kV | 115 | Brunswick EMC Cherry Grove POD | POD |
| Marion - Whiteville 115kV | 115 | Brunswick EMC Tabor City POD | POD |
| Marion - Whiteville 115kV | 115 | Chadbourn | T-D |
| Marion - Whiteville 115kV | 115 | Fair Bluff | T-D |
| Marion - Whiteville 115kV | 115 | Mullins | T-D |
| Marion - Whiteville 115kV | 115 | Nichols | T-D |
| Marion - Whiteville 115kV | 115 | Tabor City | T-D |
| Marion - Whiteville 115kV | 115 | Whiteville GA Pacific | T-D |
| Marion - Whiteville 115kV | 115 | Whiteville SE Regional Park | T-D |
| Marion - Whiteville 230kV | 230 | Brunswick EMC Chadbourn-Peacock POD | POD |
| Raeford - Lumbee River EMC Rockfish 115kV Feeder | 115 | Lumbee River EMC Arabia POD | POD |
| Raeford - Lumbee River EMC Rockfish 115kV Feeder | 115 | Lumbee River EMC Rockfish POD | POD |
| Raeford - Raeford 115kV Feeder | 115 | Lumbee River EMC Raeford POD | POD |
| Raeford - Raeford 115kV Feeder | 115 | Raeford | T-D |
| Raeford - Raeford 115kV Feeder | 115 | Raeford South | T-D |
| Raeford - Richmond 230kV | 230 | - | - |
| Richmond - DPC Newport 500kV | 500 | - | - |
| Richmond - Rockingham 230kV East | 230 | - | - |
| Richmond - Rockingham 230kV West | 230 | - | - |
| Robinson Plant - Camden Junction 115kV | 115 | Bethune | T-D |
| Robinson Plant - Florence 115kV | 115 | Darlington | T-D |
| Robinson Plant - Florence 115kV | 115 | Darlington Pineville Road | T-D |
| Robinson Plant - Florence 115kV | 115 | Hartsville | T-D |
| Robinson Plant - Florence 230kV | 230 | Dovesville Nucor | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Cheraw | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Chesterfield | T-T |
| Robinson Plant - Rockingham 115kV | 115 | Cordova Burlington Ind | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Hartsville Sonoco | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Jefferson | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Pageland | T-D |
| Robinson Plant - Rockingham 115kV | 115 | Sneedsboro Solar | Gen |
| Robinson Plant - Rockingham 230kV | 230 | Cheraw Cash Road | T-D |
| Robinson Plant - Rockingham 230kV | 230 | Cheraw Reid Park | T-D |
| Robinson Plant - SCPSA Darlington 230kV | 230 | Hartsville Segars Mill | T-D |
| Robinson Plant - Sumter 230kV | 230 | Elliott | T-D |
| Rockingham - Rockingham 115kV Tie | 115 | Pee Dee EMC Rockingham POD | POD |
| Rockingham - Rockingham 115kV Tie | 115 | Rockingham | T-D |
| Rockingham - West End 230kV East | 230 | Pee Dee EMC Derby POD | POD |
| Rockingham - West End 230kV East | 230 | West End | T-D |
| Rockingham - West End 230kV West | 230 | Eden Solar | Gen |
| Rockingham - West End 230kV West | 230 | Ellerbe | T-D |
| Rockingham - West End 230kV West | 230 | Pee Dee EMC Patterson POD | POD |

# DEP Constrained Infrastructure

| | | | |
|---|---|---|---|
| Rockingham - West End 230kV West | 230 | Wadesboro | T-D |
| Rockingham - West End 230kV West | 230 | Wadesboro Bowman School | T-D |
| Sutton Plant - Castle Hayne 115kV North | 115 | Castle Hayne | T-D |
| Sutton Plant - Castle Hayne 115kV South | 115 | - | - |
| Sutton Plant - Castle Hayne 230kV | 230 | Murraysville | T-D |
| Sutton Plant - Castle Hayne 230kV | 230 | Wilmington East | T-D |
| Sutton Plant - Castle Hayne 230kV | 230 | Wilmington Ninth & Orange | T-D |
| Sutton Plant - Delco 115kV North | 115 | Delco | T-D |
| Sutton Plant - Delco 115kV South | 115 | Brunswick EMC Wilmington POD | POD |
| Sutton Plant - Delco 115kV South | 115 | Eagle Island | T-D |
| Sutton Plant - Delco 115kV South | 115 | Leland | T-D |
| Sutton Plant - Delco 115kV South | 115 | Leland Industrial | T-D |
| Sutton Plant - Delco 115kV South | 115 | Wilmington Atlantic Scrap Metal | T-D |
| Sutton Plant - Delco 115kV South | 115 | Wilmington PCS/LA Pacificorp | T-D |
| Sutton Plant - Delco 230kV | 230 | - | - |
| Sutton Plant - Wallace 230kV | 230 | Wilmington BASF | T-D |
| Sutton Plant - Wallace 230kV | 230 | Wilmington Invista | T-D |
| Sutton Plant - Wallace 230kV | 230 | Wilmington Praxair | T-D |
| Sutton Plant - Wilmington GNF 115kV Feeder | 115 | Wilmington GNF | T-D |
| Weatherspoon Plant - Delco 115kV | 115 | Bladenboro | T-D |
| Weatherspoon Plant - Delco 115kV | 115 | Clarkton | T-D |
| Weatherspoon Plant - Delco 115kV | 115 | Elizabethtown | T-D |
| Weatherspoon Plant - Delco 115kV | 115 | Elizabethtown Cogentrix | Gen |
| Weatherspoon Plant - Delco 115kV | 115 | Kings Bluff | T-D |
| Weatherspoon Plant - Fayetteville 230kV | 230 | County Line Solar | Gen |
| Weatherspoon Plant - Fayetteville Dupont SS 115kV | 115 | Fayetteville DuPont | T-D |
| Weatherspoon Plant - Fayetteville Dupont SS 115kV | 115 | Fayetteville Solar | Gen |
| Weatherspoon Plant - Fayetteville Dupont SS 115kV | 115 | St Pauls | T-D |
| Weatherspoon Plant - Latta 230kV | 230 | Dillon Maple | T-D |
| Weatherspoon Plant - Latta 230kV | 230 | Dillon North | T-D |
| Weatherspoon Plant - Laurinburg 230kV | 230 | City of Lumberton POD #3 | POD |
| Weatherspoon Plant - Laurinburg 230kV | 230 | Rowland | T-D |
| Weatherspoon Plant - Laurinburg 230kV | 230 | Weatherspoon | T-D |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Butler | T-D |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Libbey Owens Ford | T-D |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Lumbee River EMC Pembroke POD | POD |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Lumbee River EMC West Lumberton POD | POD |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Lumberton Converse | T-D |
| Weatherspoon Plant - Libbey Owens Ford 115kV | 115 | Maxton | T-D |
| Weatherspoon Plant - Lumberton 115kV | 115 | City of Lumberton POD #4 | POD |
| Weatherspoon Plant - Lumberton 115kV | 115 | Lumberton | T-D |
| Weatherspoon Plant - Lumberton 115kV | 115 | Lumberton Cogentrix | Gen |
| Weatherspoon Plant - Marion 115kV | 115 | Dillon | T-D |
| Weatherspoon Plant - Marion 115kV | 115 | Fairmont | T-D |
| Weatherspoon Plant - Marion 115kV | 115 | Lumbee River EMC Hog Swamp POD | POD |
| Weatherspoon Plant - Raeford 115kV | 115 | City of Lumberton POD #2 | POD |
| Weatherspoon Plant - Raeford 115kV | 115 | Lumbee River EMC Red Springs POD | POD |

# DEP Constrained Infrastructure



| | | | |
|---|---|---|---|
| Weatherspoon Plant - Raeford 115kV | 115 | Lumbee River EMC Rennert POD | POD |
| Weatherspoon Plant - Raeford 115kV | 115 | Red Springs | T-D |
| Weatherspoon Plant - Raeford 115kV | 115 | Shannon | T-D |
| West End - Pinehurst 115kV Feeder | 115 | Pinehurst | T-D |
| West End - Southern Pines 115kV Feeder | 115 | Carthage | T-D |
| West End - Southern Pines 115kV Feeder | 115 | Lakeview | T-D |
| West End - Southern Pines 115kV Feeder | 115 | Randolph EMC Eastwood POD | POD |
| West End - Southern Pines 115kV Feeder | 115 | Southern Pines | T-D |
| West End - Southern Pines Center Park 115kV Feeder | 115 | Aberdeen | T-D |
| West End - Southern Pines Center Park 115kV Feeder | 115 | Southern Pines Center Park | T-D |
| - | - | Barnard Creek | T-T |
| - | - | Bennettsville SS | T-T |
| - | - | Biscoe | T-T |
| - | - | Blewett Falls Plant | T-T |
| - | - | Brunswick Plant Unit 1 | T-T |
| - | - | Brunswick Plant Unit 2 | T-T |
| - | - | Camden Junction | T-T |
| - | - | Cape Fear Plant | T-T |
| - | - | Castle Hayne | T-T |
| - | - | Clinton | T-T |
| - | - | Cumberland | T-T |
| - | - | Darlington County Plant | T-T |
| - | - | Delco | T-T |
| - | - | Erwin | T-T |
| - | - | Fayetteville | T-T |
| - | - | Fayetteville Dupont SS | T-T |
| - | - | Florence | T-T |
| - | - | Florence Dupont | T-T |
| - | - | Florence Roche Carolinas | T-T |
| - | - | Folkstone | T-T |
| - | - | Ft. Bragg Woodruff St. | T-T |
| - | - | Harris Plant | T-T |
| - | - | Jacksonville | T-T |
| - | - | Jacksonville City | T-T |
| - | - | Kingstree | T-T |
| - | - | Latta | T-T |
| - | - | Laurinburg | T-T |
| - | - | Libbey Owens Ford | T-T |
| - | - | Lilesville | T-T |
| - | - | Manchester | T-T |
| - | - | Marion | T-T |
| - | - | Raeford | T-T |
| - | - | Richmond | T-T |
| - | - | Robinson Plant | T-T |
| - | - | Rockingham | T-T |
| - | - | Sumter | T-T |
| - | - | Sutton Plant | T-T |

# DEP Constrained Infrastructure

| | |
|---|---|
| - Tillery Plant | T-T |
| - Town Creek | T-T |
| - Vander | T-T |
| - Wake | T-T |
| - Wallace | T-T |
| - Weatherspoon Plant | T-T |
| - West End | T-T |
| - Whiteville | T-T |
| - Wilmington Corning SS | T-T |

# DEC Constrained Infrastructure

| Line Name | Operating Name | kV | Substation | Type |
|---|---|---|---|---|
| Belton-Toxaway | Anderson B | 100 | - | - |
| Belton-Toxaway | Anderson W | 100 | - | - |
| Greenwood-Clark Hill | Bond B | 100 | - | - |
| Greenwood-Clark Hill | Bond W | 100 | - | - |
| Belton-Lee | Broadway B | 100 | - | - |
| Belton-Lee | Broadway W | 100 | - | - |
| Bush River-Creto | Champion B | 100 | - | - |
| Bush River-Creto | Champion W | 100 | - | - |
| Great Falls-Cedar Creek | Cedar Creek B | 100 | - | - |
| Great Falls-Cedar Creek | Cedar Creek W | 100 | - | - |
| Great Falls-Chester | Chester B | 100 | Black Creek Retail | T-D |
| Great Falls-Chester | Chester W | 100 | East Chester Retail | T-D |
| Clark Hill-JST | Clark Hill | 115 | - | - |
| Laurens-Bush River | Clinton B | 100 | - | - |
| Laurens-Bush River | Clinton W | 100 | Clinton Tie | T-T |
| Coronaca-Hodges | Cokesbury B | 100 | Mulberry Creek Retail | T-D |
| Coronaca-Hodges | Cokesbury W | 100 | - | - |
| Creto-Coronaca | Coronaca | 100 | Emerald Rd Retail | T-D |
| Hodges-Cypress | Cypress B | 100 | - | - |
| Hodges-Cypress | Cypress W | 100 | - | - |
| Dan River-N Greensboro | Dan River B | 100 | Rudd Retail, Waynick Retail | T-D |
| Dan River-N Greensboro | Dan River W | 100 | Lake Townsend Retail, Wentworth Retail | T-D |
| Guardian-Bowater | Edgemoor B&W N | 100 | - | - |
| Great Falls-Guardian | Edgemoor B&W S | 100 | - | - |
| Toxaway-Anderson | Fiber B | 100 | - | - |
| Toxaway-Anderson | Fiber W | 100 | - | - |
| Fishing Creek-Lancaster | Fishing Creek B N | 100 | - | - |
| Great Falls-Fishing Creek | Fishing Creek B S | 100 | - | - |
| Great Falls-Lancaster | Fishing Creek W | 100 | - | - |
| Greenwood-Hodges | Greenwood B | 100 | Johns Creek Retail | T-D |
| Greenwood-Hodges | Greenwood W | 100 | - | - |
| Hodges-Belton | Hodges B | 100 | - | - |
| Hodges-Belton | Hodges W | 100 | - | - |
| Great Falls-Bowater | Landsford B N | 100 | - | - |
| Great Falls-Bowater | Landsford B S | 100 | - | - |
| Great Falls-Bowater | Landsford W | 100 | - | - |
| Dan River-Madison | Mayo B | 100 | Dan Valley Retail | T-D |
| Dan River-Madison | Mayo W | 100 | Ridgeview Retail | T-D |
| Lancaster-Monroe | Monroe B | 100 | Lancaster Retail, Red Rose Retail, Roughedge Retail | T-D |
| Lancaster-Monroe | Monroe B | 100 | Roughedge Tie | T-T |
| Lancaster-Monroe | Monroe W | 100 | Mini Ranch Retail | T-D |
| Dan River-Meadow Green Retail | Motley B | 100 | Meadow Green Retail | T-D |
| Dan River-Meadow Green Retail | Motley W | 100 | Motley Tie | T-T |
| Bush River-Saluda | Newberry B | 115 | - | - |
| Bush River-Saluda | Newberry W | 115 | - | - |
| Chester-Newport | Parr W | 100 | - | - |

## DEC Constrained Infrastructure

| | | | | |
|---|---|---|---|---|
| Lee-Laurens | Rabon B | 100 | - | - |
| Lee-Laurens | Rabon W | 100 | - | - |
| Dan River-Sadler | Reidsville B | 100 | - | - |
| Dan River-Sadler | Reidsville W | 100 | - | - |
| Dan River-Ridgeway | Ridgeway | 115 | - | - |
| Chester-Leeds | Robat B | 100 | - | - |
| Creto-Greenwood | Thrush B | 100 | - | - |
| Creto-Greenwood | Thrush W | 100 | - | - |
| Toxaway-Lee | Toxaway B | 100 | - | - |
| Toxaway-Lee | Toxaway W | 100 | - | - |
| Wateree-Great Falls | Wateree B | 100 | - | - |
| Wateree-Great Falls | Wateree W | 100 | - | - |
| Dan River-Sadler | Wolf Creek B | 100 | - | - |
| Dan River-Sadler | Wolf Creek W | 100 | - | - |
| | Belton | 44 | Ware Place Retail | T-D |
| | Blair | 44 | Belton Retail | T-D |
| | Coronaca Retail | 44 | Coronaca Retail | T-D |
| | Eden 1 | 44 | Draper Retail | T-D |
| | Enoree 2 | 44 | Blakley Retail | T-D |
| | Florida | 44 | Bradley Retail, Florida Retail, Forest Hill Retail, Utopia Retail | T-D |
| | Gateway 2 | 44 | N Greenwood Retail | T-D |
| | Great Falls 5 | 44 | Nitrolee Retail | T-D |
| | Hampton Street Retail | 44 | Hampton Street Retail | T-D |
| | Honea Path | 44 | Docheno Ret, Honea Path Ret | T-D |
| | Longtown Retail | 44 | Longtown Retail | T-D |
| | Madison | 44 | Bryant St Retail, Mayodan Retail, Stoneville Retail | T-D |
| | Morehead | 44 | Leaksville Retail | T-D |
| | Ninety-Six | 44 | Ninety-Six Retail | T-D |
| | Orr | 44 | McDuffie St Retail | T-D |
| | Pleasant Hill | 44 | Elgin Retail, Tradesville Retail | T-D |
| | Red River 1 | 44 | Lando Retail | T-D |
| | Red River 2 | 44 | Fort Lawn Retail, Great Falls Retail | T-D |
| | Rocky Creek 3 | 44 | Kershaw Retail | T-D |
| | Sandy Springs | 44 | Green Pond Retail | T-D |
| | Sweetgum 2 | 44 | Abbeville Retail | T-D |
| | Toxaway Retail | 44 | Toxaway Retail | T-D |
| | Tribble Street | 44 | North Street Retail, Tribble Street Retail | T-D |
| | Trinity | 44 | Trinity Ridge Retail | T-D |
| | Van Wyck | 44 | Erwin Farms Retail | T-D |
| | Watts Mill | 44 | Ora Retail | T-D |
| | Whitner | 44 | Neals Creek Retail | T-D |
| | Williamston | 44 | Williamston Retail | T-D |
| | Wilson Creek | 44 | Eddy Rd Retail, Panorama Retail | T-D |

## 20 kW to 2 MW Size PV (Inverter) Based Installation

Below are the 11 categories (screens) addressed in
NC State Jurisdictional Interconnection Standard Section 3.2.1. (May 15, 2015)

Project Name: Name
Size: 0.0288 MW (AC)

| | Screens | Pass/Fail | Comments |
|---|---|---|---|
| 3 2.1.1 | The proposed Generating Facility's Point of Interconnection must be on a portion of the Utility's Distribution System. | Pass | |
| 3 2.1 2 | For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line. | Fail | 28.8 kW project is 60% of annual line section peak load |
| 3 2.1 3 | For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 90% of the circuit and/or bank minimum load at the substation. | Pass | |
| 3 2.1.4 | All synchronous and induction machines must be connected to a distribution circuit where the local minimum load to generation ratio on the circuit line segment is larger than 3 to 1. A 3-1 load to generation ratio screen utilizes actual recorded data that is sufficient to establish the minimum threshold. | N/A | |
| 3 2.1 5 | For interconnection of a proposed Generating Facility to the load side of spot network protectors, the proposed Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5% of a spot network's maximum load or 50 kW. | N/A | |
| 3 2.1.6 | The proposed Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership. | Pass | |
| 3 2.1.7 | The proposed Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5% of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5% of the short circuit interrupting capability. | Pass | |
| 3 2.1 8 | Using the table below, determine the type of interconnection to a primary distribution line. This screen includes a review of the type of electrical service to be provided to the Interconnection Customer, including line configuration and the transformer connection for the purpose of limiting the potential for creating over-voltages on the Utility's System due to a loss of ground during the operating time of any anti-islanding function.<br><u>Primary Distr Line Type / Type Of Interconnection</u><br>A: Three-phase, three wire / 3-phase or single phase, phase-to-phase<br>B: Three-phase, four wire / Effectively-grounded 3 phase or Single-phase, line-to-neutral | Pass | |
| 3 2.1 9 | If the proposed Generating Facility is to be interconnected on a single-phase shared secondary, the aggregate Generating Facility capacity on the shared secondary, including the proposed Generating Facility, shall not exceed 65% of the transformer nameplate rating. | N/A | |
| 3 2.1.10 | If the proposed Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20% of the nameplate rating of the service transformer. | N/A | |
| 3 2.1.11 | The Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection). | Pass | |

**From:** DEC Customer Owned Generation
**Subject:** Fast Track Results – NC2018-XXXX – Name
**Attachments:** Fast Track.pdf

Good Morning,

The project NC2018-XXXX – Name has failed Fast Track.

As stated in the North Carolina Interconnection Procedures, Forms, and Agreements, the criteria failed are stated as follows:

3.2.1.2 For interconnection of a proposed Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Generating Facility, on the circuit shall not exceed 15% of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Utility's System connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

With your approval, a Supplemental Review can be performed to determine an option for your project to remain in the Fast Track process. At the conclusion of the Supplemental Review, the results will be shared with you. The cost for this review is $250, therefore your approval is required. If you wish to proceed with the Supplemental Review, please send the above deposit to either of the addresses below. On the memo line of your payment, please write "Name Supplemental Review Deposit".

Mailing Address:
Duke Energy Carolinas
Attention: Customer Owned Generation - Mail Code ST14Q
P.O. Box 1010
Charlotte, NC 28201

Overnight Mailing Address:
Duke Energy Carolinas
Attention: Customer Owned Generation - Mail Code ST14Q
400 South Tryon Street Charlotte, NC 28202

If you do not wish to proceed with the supplemental review, please respond to designate whether you would like to withdraw your project or proceed with the study phase. If you would like to proceed directly to the study phase, please indicate as such and the appropriate forms will be sent to you.

Attached are the Fast Track results.

Per the NC Interconnection Procedures (Docket No. E-100, Sub 101) section 1.4.4, "If the Interconnection Request Application Form and/or the initial supporting documentation is incomplete, the Utility shall provide, along with notice that the information is incomplete, a written list detailing all information that must be provided. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. If the terconnection Customer does not provide the listed information or a request for an extension of time, not to exceed ten (10) additional Business Days, within the deadline, the Interconnection Request will be deemed withdrawn.

A response is required by XX/XX/18.

Thank you,

Duke Energy Carolinas

**From:** DEC Customer Owned Generation
**Subject:** Supplemental Review – NC2018-XXXX – Name

Good Morning,

The supplemental review for your project NC2018-XXXX- Name has been completed. We are prepared to pass this project at the full requested output size of 28.8kW. Before this project can be released to our account managers to complete the remainder of the process, the following items need to be addressed.

1. Based on your requested size, acknowledge that your project will meet the following protection requirements is needed:
   a. Inverters have to be tested and listed for compliance with the latest published edition of underwriter laboratories Inc., UL 1741 for utility interactive inverters.
   b. Interconnection protection equipment shall comply with the latest edition of IEEE 1547 and applicable series standards.
   c. Single-phase inverters shall be manufactured after November 7, 2000.
   d. Three-phase inverters shall be manufactured after May 7, 2007
   e. Voltage and frequency set-points must be same as "default".
   f. A manual load-break rated disconnect switch to serve as a clear visible indication of switch position between the utility and the interconnection customer is required. The switch must be lockable in the open position, adjacent to the meter and readily accessible to utility personnel.
2. Please indicate on your one line diagram the figure that best reflects your connection type based on those in the manual linked below, particularly figures 63 through 72G:
   a. https://www.duke-energy.com/ /media/pdfs/partner-with-us/service-requirements-manual.pdf
3. An updated one line diagram reflecting the following changes is needed:
   a. Please ensure that the one-line reflects the indicated figure.
   b. "The submission of this drawing acknowledges this is the final design and any change to this diagram could result in a material modification as defined by the state interconnection standards. Any changes to this diagram must be submitted for approval to Duke Energy Carolinas." must be stated on the one line diagram.
   c. "Maximum AC Physical Export Capability Requested: 28.8kW" must be stated on the one line diagram.

Please respond to this email addressing the items above.

Per the NC Interconnection Procedures (Docket No. E-100, Sub 101) section 1.4.4, "If the Interconnection Request Application Form and/or the initial supporting documentation is incomplete, the Utility shall provide, along with notice that the information is incomplete, a written list detailing all information that must be provided. The Interconnection Customer will have ten (10) Business Days after receipt of the notice to submit the listed information. If the Interconnection Customer does not provide the listed information or a request for an extension of time, not to exceed ten (10) additional Business Days, within the deadline, the Interconnection Request will be deemed withdrawn."
A response is required by XX/XX/2018.

l responses must come from a contact listed on the attached Interconnection Request Application. If you wish for us to communicate with an individual who is not listed on the Interconnection Request Application for this project, you must file an updated version of the form naming the desired contact(s) as a primary or alternative contact with DERContracts@duke-energy.com.

Thank you,

Duke Energy Carolinas

**Sloan, Megan**

**From:** Sloan, Megan
**Sent:** Tuesday, October 30, 2018 1:21 PM
**To:** Sloan, Megan
**Subject:** Facility Study Results example

**From:** DERContracts
**Sent:** Wednesday, October 10, 2018 2:55 PM
**To:** [redacted]
**Subject:** [redacted]

Dear [redacted],

The Interconnection Facilities and System Upgrades (the Facility Study) design and cost estimation for [redacted], NC2016-[redacted] is complete. Per North Carolina Interconnection Procedures (NCIP) Section 5.1, at this time you have the option to request a Construction Planning Meeting within 10 business days of receiving this Facility Study Report.

**Cost Estimations**

The estimated installed cost of the *System Upgrades* is **$3,055.36.** That amount, and the estimated administrative overhead costs/commissioning costs which total **$35,000.00,** are due as a **one-time payment = $38,055.36. 7% NC** utility sales tax will apply to the System Upgrades and the commissioning costs. Based on the NCIP Section 5.2, these upfront amounts are due no later than 60 Calendar Days after the executable Interconnection Agreement (IA) is delivered to you for signature, and the IA must be signed within 10 business days of being delivered to you.

The estimated installed cost of the *Interconnection Facilities* is $28,183.03 plus 7% North Carolina Utility Sales Tax . This cost is typically borne by the Interconnection Customer in the form of a monthly charge equal to 1.0% of the installed cost of the Interconnection Facilities. Based on this, the ongoing **monthly charge** is estimated to be **$301.56 (including tax),** and will begin after we complete construction of our facilities. There is an additional power quality metering and control cost that will eventually be required as part of the *Interconnection Facilities*, but this is not included in the installed cost or monthly cost listed above. When that cost is determined, and after the meter is installed, the monthly cost will be adjusted to reflect it. Based on information in hand, we estimate the impact at less than $300 additional per month.

All estimated costs are subject to being trued-up to actuals after construction, and the IA amended.

**Next Steps**

Within 10 business days, please provide in writing:

1. Your requested in-service date for Duke facilities to be in place and operational. If this request date cannot be accommodated, we will advise you of the earliest possible date.
2. Response indicating whether or not you would like to request a Construction Planning Meeting.
   a) If you request a Construction Planning Meeting, we will schedule the meeting as soon as a mutually agreeable date is determined. Duke Energy will not be able to tender an IA until after the occurrence of the Construction Planning Meeting. At such time, the IA would be delivered within 15 business days after the Construction Planning Meeting.

b) If you do not request a Construction Planning Meeting, Duke Energy will proceed by tendering an executable IA within 15 business days after receipt of your requested in-service date and your right to a Construction Planning Meeting shall be deemed waived.

Regards,

*Shane Judd*

Wholesale Renewable Manager
400 South Tryon Street, Charlotte, NC 28202
shane.judd@duke-energy.com

DUKE ENERGY.

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CAROLINAS

***Transmission System Impact Review Disclaimer***

*In an effort to keep the distribution interconnection process moving, in the enclosed we are providing your interim SIS Report. Please note, Duke Energy has not completed a Transmission System Impact Review for this project, so this interim report only reflects impacts to the Distribution System. Upon completion of the Transmission System Impact Review, this interim report will be updated. If the customer relies on this interim report to authorize Duke Energy to proceed with additional System Impact Study or with a Facilities Study, the customer understands and accepts the risk that transmission impacts may be identified and transmission upgrade costs may be assigned.*

**Project A**

**NC2017-xxxxx**

# Proposed Generating Facility

# System Impact Study Report

# Duke Energy Carolinas (DEC)

## Table of Contents

## Preface

The System Impact Study is designed to identify and detail the electric system impacts associated with interconnecting the proposed Generation Facility and to identify System Upgrades and Interconnections Facilities needed to interconnect the facility and correct any system problems identified in the study. The study is based on the point of interconnection proposed by the Interconnection Customer and on technical information provided in the Interconnection Request. In addition to detailing the required Interconnection Facilities and System Upgrades, the study provides a preliminary, non-binding estimate of the cost and length of time necessary to provide the facilities and upgrades.

## Interconnection Data

**Interconnection Customer:** Project A

**Queue Number:** NC2017-xxxxx

**Maximum Physical Export Capability Requested:** 2,000 kW

**Generating Facility Equipment:**

- PV Panels: <Make And Model Of Panels>– Quantity 9,082
    - 330 Watt Panels
- Inverters: <Make And Model Of Inverters> – Quantity 1
    - UL1741 Compliant
    - Rated Output Power of 2,000 kW
    - Nominal Apparent Power of 2,200 kVA
    - Operating Voltage: 385 V
- Transformers: 2,000 kVA – Quantity 1
    - Manufacturer:
    - Primary (Utility) Winding: 12.47 kV Wye-Grounded
    - Secondary (Inverter) Winding: 385 V Wye-Ungrounded
    - 6% Impedance

## Circuit Information

**Substation Name:** Duke Energy Substation

**Feeder Number:** xxxxxxxx

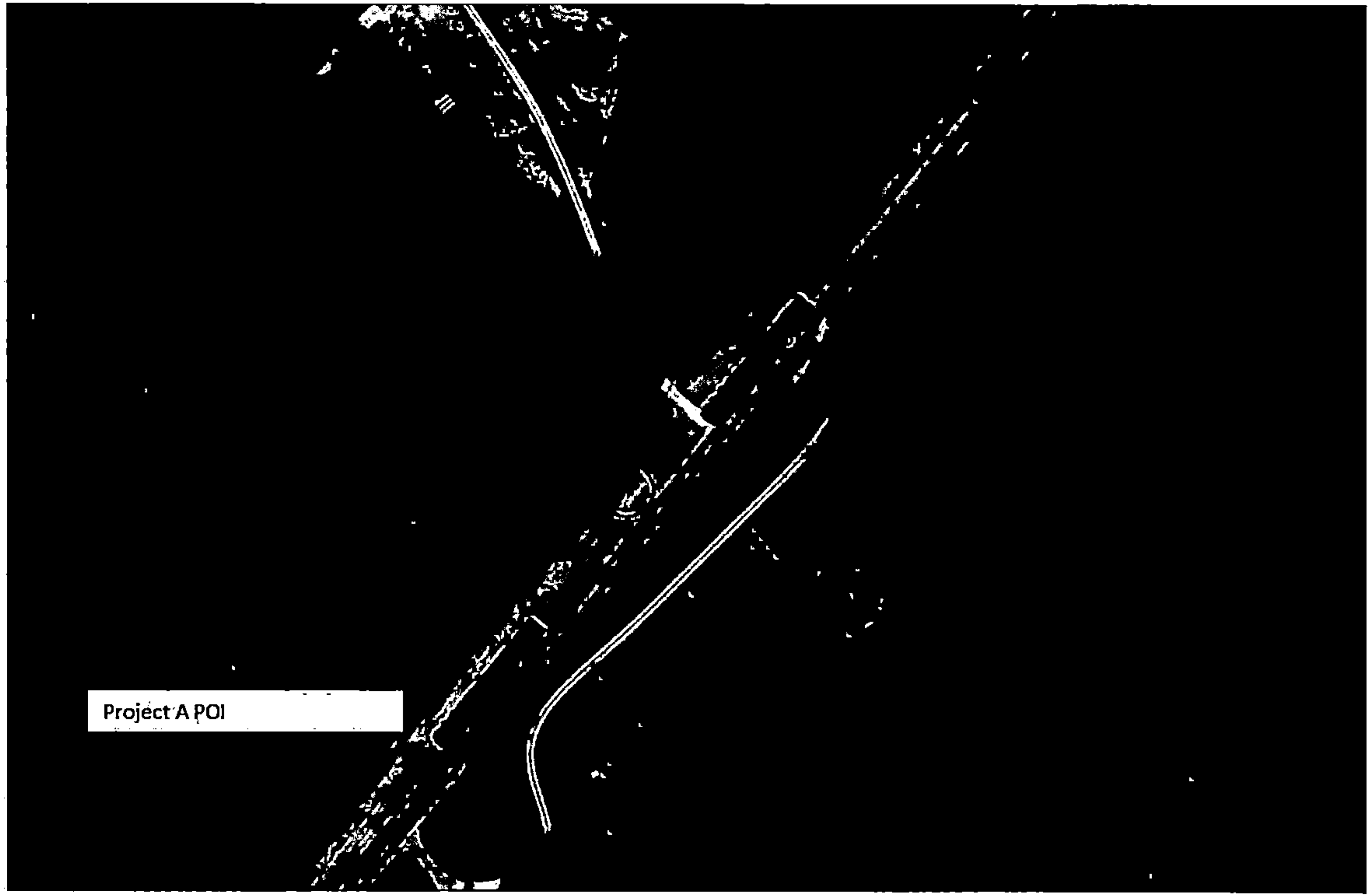
**Point of Interconnection (POI):** <Latitude>°, <Longitude>°

**Nominal Voltage:** 12.5 kV

**Existing/Proposed Generating Facilities Ahead On Feeder:** None

**Existing/Proposed Generating Facilities Ahead On Substation:** None

Figure 1 - Point Of Interconnection



## Distributed Energy Resource Planning & Interconnection Guidelines

The Generating Facility was reviewed in conjunction with the DEC & DEP: Distributed Energy Resource (DER) Method Of Service Guidelines for DER No Larger Than 20 MW ("Guidelines") to determine the applicable path for interconnection. A link to the Guidelines is provided below.

https://www.duke-energy.com/business/products/renewables/generate-your-own

As determined by the design of the Generating Facility and the Maximum Physical Export Capability Requested on the Interconnection Request, the Interconnection Customer will interconnect to the DEC system as Method "D", as defined in Section 2.2 of the Guidelines.

The Interconnection Customer's POI is within the first regulated zone of the DEC distribution system. As such, no new line extensions were required in order to accommodate the Interconnection Customer. As such, the POI for this installation will be at the end of the interconnection facilities. The interconnection facilities will be located on the Interconnection Customer's property.

The short circuit capability at the POI is 47.2 MVA. The short circuit capability at the substation bus is 65.3 MVA. This equates to the Interconnection Customer having a Stiffness Factor of 23.60 and 32.65 at the POI and substation bus, respectively. The Interconnection Customer fails the POI Stiffness Factor, as defined in Section 3.4 of the Guidelines.

## Circuit Breaker Short Circuit Capability Limits

The POI is electrically downstream of non-electronic protective devices (i.e. fuses, or hydraulic reclosers). The protective scheme of the circuit needed to be altered such that only electronic devices exist upstream of the Interconnection Customer's POI while maintaining the reliability for DEC retail customers. These alterations include, but are not limited to, replacing devices with electronic reclosers and installing/relocating devices. A detailed listing of the System Upgrades that satisfied these requirements can be found in the Results Section below The Interconnection Customer will be responsible for these System Upgrades.

No interrupting rating concerns were identified with the addition of the Generating Facility to the DEC distribution system.

The addition of the Generating Facility causes service transformers to be added to the high fault area. Service transformers within this area are retrofitted with current limiting fuses to minimize the chance of tank ruptures. In order to remediate these issues, the Interconnection Customer will be responsible for retrofitting the following transformers to incorporate current limiting fuses, also known as High Fault Tamers.

| Transformer ID | Phase | LLL (A) | LLG (A) | LL (A) | LG (A) |
|---|---|---|---|---|---|
| 40283033 | 1Ø | 3093 | 3238 | 2679 | 3340 |

Table 1 – High Fault Area Violations

A detailed listing of these System Upgrades can be found in the Results section below.

## Thermal Overload Or Voltage Limit Violations

The interconnection of a Generating Facility shall not cause the service voltage to exceed DEC's distribution voltage standards. Additionally, the interconnection of a Generating Facility shall not cause the voltage change to exceed the limits defined in the document entitled RVC (Rapid Voltage Change) and Flicker Study Criteria ("Flicker"), attached in the Appendix at the end of this report. After evaluating the addition of the Generating Facility at the requested size of 2,000 kW, it was determined that there are service voltage and Flicker violations.

The results of the evaluations are detailed in the Tables below. The "Retail Customer" refers to the location of a DEC retail customer who has the potential to experience the greatest effect with the addition of the Generating Facility. The Retail Customer may not refer to the same location between peak and valley circuit loading conditions. The "Substation" location refers to the regulated side of the substation. The voltages are presented on a 120V base and represent the medium voltage (primary) level.

| Location | $V_A$ | $V_B$ | $V_C$ | RVC Criteria "A" |
|---|---|---|---|---|
| Retail Customer | 121.6 - Pass | 123.9 - Pass | 121.5 - Pass | 0.85 % - Pass |
| POI | 123.5 - Pass | 124.6 - Pass | 124.1 – Pass | 0.83 % - Pass |
| Substation | 124.3- Pass | 124.2 - Pass | 124.6 - Pass | 0.41 % - Pass |

Table 2 - Voltage Limit Results – Peak Circuit Loading with Existing Infrastructure

| Location | $V_A$ | $V_B$ | $V_C$ | RVC Criteria "A" |
|---|---|---|---|---|
| Retail Customer | 125.2 - Pass | 126.1 - Fail | 125.9 - Pass | 0.63 % - Pass |
| POI | 125.2 - Pass | 126.1 - Fail | 126.0 - Pass | 0.63 % - Pass |
| Substation | 125.1 - Pass | 125.6 - Pass | 125.7 - Pass | 0.22 % - Pass |

Table 3 - Voltage Limit Results – Valley Circuit Loading with Existing Infrastructure

Reconductoring the existing infrastructure remediated the violations identified above. A detailed listing of the System Upgrades that remediated the violations can be found in the Results section below. With the remediation incorporated, the revised results are detailed in the Tables below.

| Location | $V_A$ | $V_B$ | $V_C$ | RVC Criteria "A" |
|---|---|---|---|---|
| Retail Customer | 121.8 - Pass | 124.0 - Pass | 122.1 - Pass | 0.78 % - Pass |
| POI | 123.6 - Pass | 124.5 - Pass | 124.0 - Pass | 0.77 % - Pass |
| Substation | 124.3 - Pass | 124.2 - Pass | 124.6 - Pass | 0.40 % - Pass |

Table 4 - Voltage Limit Results – Peak Circuit Loading Incorporating Remediation

| Location | $V_A$ | $V_B$ | $V_C$ | RVC Criteria "A" |
|---|---|---|---|---|
| Retail Customer | 125.2 - Pass | 126.0 - Pass | 125.9 - Pass | 0.57 % - Pass |
| POI | 125.2 - Pass | 126.0 - Pass | 125.9 - Pass | 0.57 % - Pass |
| Substation | 125.1 - Pass | 125.6 - Pass | 125.7 - Pass | 0.22 % - Pass |

Table 5 - Voltage Limit Results – Valley Circuit Loading Incorporating Remediation

No thermal overload issues were identified. The conductors between the substation and the POI are adequate to support the addition of the Generating Facility.

The existing 4.5 MVA substation transformer can adequately support the Interconnection Customer.

## Grounding Requirements And Electric System Protection

The Generating Facility will supply a transformer connected in the Wye-Grounded (utility) / Wye-Ungrounded (inverter) configuration. This configuration is acceptable for interconnection to the DEC system.

The interconnection facilities for the Generating Facility will be as per Figure 71B of the Requirements for Electric Service and Meter Installations manual, link provided below.

https://www.duke-energy.com/_/media/pdfs/partner-with-us/service-requirements-manual.pdf

The requirements for the Generating Facility are as follows, as per Figure 75C:

a) Interconnection protection will be owned and operated by DEC and is to include a recloser, relaying (control), and remote communications for monitoring and operations.
   i. Protection will utilize over current, under/over voltage, and under/over frequency relaying.
b) DEC shall provide a manual load-break rated disconnect switch to serve as a clear visible indication of switch position between the utility and the Interconnection Customer. The switch must be readily accessible to DEC personnel.
c) Interconnection Customer's inverters have to be tested and listed for compliance with the latest published edition of Underwriter Laboratories Inc., UL 1741 for utility interactive inverters.
d) Interconnection Customer shall comply with the latest edition of IEEE 1547 and applicable series standards.

These requirements and the interconnection Figure are subject to change at any time.

A power quality (PQ) meter will also be installed with the interconnection facilities to continuously monitor the power quality impacts of the generating facility to the DEC system.

The Generating Facility is to be operated such that unity power factor is continuously maintained at the Point of Interconnection (where utility-owned metering is located).

## Other Technical Requirements

System Upgrades within the substation are required in order to provide the functionality for equipment to sense reverse power flow as the Generating Facility is expected to backfeed power into the substation. A detailed listing of these System Upgrades can be found in the Results section below.

## Results

As a result of the interconnection of the Generating Facility, the System Upgrades detailed above will be required at the responsibility of the Interconnection Customer. A more in depth listing of these System Upgrades is detailed below.

1. Transmission Upgrades:
    a. TBD
2. Substation Upgrades:
    a. Install a 4 quadrant bank meter.
    b. Replace A&B&C phase feeder regulator controls with Beckwith 2001D controls (x3) if the current controls are not cogeneration capable (controls are unknown).
    c. 1201 Feeder regulator 39022986 to be set to co-generation mode with a 125V reverse band center.
3. New Line Construction/Reconductoring:
    a. Reconductor existing 3Ø 336 AAC with 1/0 ACSR neutral to 3Ø 556 AAC with 556 AAC neutral from the 1201 circuit exit (wire 37010243) to the end of wire 36349907; approximately 0.48 miles.
4. Protection Upgrades/Sectionalization:
    a. Retrofit the following transformers with High Fault Tamers:
        i. 1Ø 40283033
    b. Replace 3Ø 200A V4H recloser 39003514 with a G&W Viper recloser.
5. Other:
    a. None.
6. Interconnection Facilities:
    a. Standard Interconnection Package connected as per Figure 71B.

The estimated Monthly Interconnection Facilities Charge is $974.98. The estimated One-Time Charge for the required upgrades is $256,419.96. These estimates are non-binding and are detailed in the Table below. Additionally, these estimates are only for the work required on the utility side of the POI.

| | Cost |
|---|---|
| Transmission Upgrades | $0 |
| Substation Upgrades | $10,369.16 |
| New Line Construction/Reconductoring | $167,232.00 |
| Protection Upgrades/Sectionalization | $78,818.80 |
| Other | $0 |
| Total Upfront Charges | $256,419.96 |

Table 6 - Estimated One-Time Charge

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## DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

**Request**:

Please provide the following information related to energy storage projects.

a. Identify how many Interconnection Requests Duke has received for systems including energy storage, by the following categories:
   i. Standalone storage facilities,
   ii. Co-located storage facilities,
   iii. Exporting storage facilities, and
   iv. Non-exporting storage facilities.

b. For proposed non-exporting storage facilities, how has Duke determined the appropriate level of review for the facility (e.g., 20 kW process, Fast Track, Section 4 Study Process)?

c. Describe any challenges Duke has identified in studying and interconnecting energy storage projects.

**Response**:

**Duke Response 1-5a.**

a. DEC and DEP have received a variety of IRs including energy storage. Two facilities are being proposed as stand-alone storage facilities. Duke has received notification of over 60 customers that have ordered residential energy storage. Specifically, an installer has contacted Duke by email listing a number of customers (over 60) that have ordered residential energy storage. Many of these customers already have solar online. However, these projects likely already have generation or plan to install generation.

   There are significantly more IRs for co-located storage facilities. Not including the over 60 customers mentioned above, there are over 100 Interconnection Requests for co-located storage facilities. This number is mostly residential projects that have already connected but also includes utility-owned projects, large customers projects, and 3rd party-owned utility-scaled solar facilities. Currently, there is no place on the IR form for energy storage identification. To date, Duke Energy has informally tracked requests for interconnection of energy storage facilities.

   The only facilities proposing to export are the 31 utility-owned and 3rd party-owned utility-scale solar facilities.

**Duke Response 1-5b.**

b. For projects under 20 kW, the Duke Utilities have a checklist to ensure that these projects are designed to be non-exporting, have been approved by a licensed electrical contractor, have a visible disconnect switch available to the utility and that the equipment meets appropriate industry standards.

   For projects greater than 20 kW, projects are reviewed by an engineer.

**Duke Response 1-5c.**

c. IRs do not provide a lot of information on how the energy storage is intended to be controlled and operated. This information is important for determining how it should be studied. For example, solar generation has a relatively similar generation profile (hours of the day, ramp rates) regardless of location or system design.

   Based on the intended use of the energy storage, it may require additional protection and communications that are not required of most distributed energy resources. See also Duke's response to Public Staff Data Request No. 5, item 5-8.

Interstate Renewable Energy Council
Data Request No. 1
Docket No. E-100, Sub 101
NCIP
Item No. 1-6

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide the following information related to interconnection processing costs.

a. What is the average cost to Duke to process a <20 kW Interconnection Request?
b. What is the average cost to Duke to process a Fast Track Interconnection Request?

**Response:**

In response to both a. and b., Duke Energy does not track average costs or expenses specifically for processing a <20 kW Interconnection Request or a Fast Track Interconnection Request, and therefore has no data reasonably available to provide the "average cost" information sought in these requests.

Instead, Duke Energy sets up its expense tracking based on *type* of work in order to better match against cash received. There are three general "types" of work tracked to match against cash received. The three main "buckets" to track the type of work with the cash received are as follows:

Bucket 1: Process-related costs to be recovered from receipt of non-refundable fees as outlined in the NC Interconnection Procedures. Note both 6.a. and 6.b. processes would be included in this Bucket 1.

Bucket 2: Deposits anticipated to cover costs related to performance and tracking of study-related costs.

Bucket 3: Payments anticipated to cover estimated costs of construction of interconnection facilities and system and/or network upgrade costs, including overheads

As shown above, 6.a. and 6.b. processes are tracked in Bucket 1. Using the total estimated expenses of $1.1M in Bucket 1, divided by the 3,868 volume of < 2MW IRs anticipated in 2018, equates to an estimated cost $294 per IR. However, please note this is skewed estimate as majority of volume is <20 kW applications.

1058634.1

I/014
A/0015



Exhibit SBA-Direct-9

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please confirm the Companies intends to include the Updated Section 2 Fee Proposal in their November 19 testimony.

**Response:**

The Companies intend to include the Updated Section 2 Fee Proposal in their November 19 testimony. Notably, on November 6, 2018, counsel for the Companies notified all intervenors to this docket of the Companies' plans to address the updated Section 2 fee proposal in testimony.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Page 7 of the slide deck indicates estimated application processing expenses for projects < 2MW of $1,387,530 for 2018 (annualized) and $1,391,046 for 2019 (estimated). Please provide an estimate of (i) the application processing expenses for projects > 2 MW in 2018 and 2019 and (ii) the total application processing expenses for all interconnection customers in 2018 and 2019.

a. Please provide a narrative explaining how the total application processing expenses are assigned to <2MW and >2MW projects. Please provide supporting calculations, in functional Excel spreadsheets.

**Response:**

a. The narrative below attempts to explain the charging process. The Companies currently do not have the capability to differentiate "application processing expenses" from other interconnection-related support expenses between projects < 2 MW and > 2 MW.

Employees supporting interconnection processes unrelated to customer-specific project codes for study, engineering planning, and construction work are directed to charge their time to the charge codes below in order to aggregate these costs for overall cost recovery purposes. These employees and Contingent Workers report under the Renewables Service Center, divisions within Distributed Energy Technology, Distributed Generation studies, and/or Transmission planning general support.

The general cost categories employees charge attempt to align with cash received from Interconnection Customers. This charging methodology was introduced in 4Q17, though the Companies continue to review and refine the process in order to better guide employees on best practices for how best to differentiate charging.

The cost categories are:

**Fees-Recovered Work** (charged to project code ICREVIEW)

- These charges are related to <.2 MW Interconnection Request and Pre-Application processing expenses, time spent processing and filing change of control documentation and related technology costs. Costs for this type of work are recovered via non-refundable fees. Since these costs are not allocated to specific customers, the net balance in project code ICREVIEW reflects either over or under-recovery of these costs, thereby allowing Duke Energy to determine whether fees should be adjusted higher or lower.

**Study-Recovered Work** (Charged to project codes ICSTUDYD or ICSTUDYT, depending on whether the work supports distribution or transmission projects.

- These costs are driven by processing the >2 MW state-jurisdictional Interconnection applications, answering questions and preparing agreements for Supplemental Reviews, System Impact Study Agreements, Facility Study Agreements, tracking and filing correspondence, general account management, process and oversight and related technology costs. These costs are aggregated and then allocated to specific customer project codes based on the Admin. Table presented in request 3. below. The net balance in the Study project codes will reflect whether administrative costs are set at correct amounts based on project volumes and hours charged.

**Construction Cost-Recovered Work** (Charged to project codes ICCONSTRD or ICCONSTRT, depending on whether the work supports distribution or transmission projects.

- These costs are driven by preparing the Interconnection Agreements, answering questions/following up with customers and managing internal questions, tracking and filing correspondence, general account management and oversight, and related technology costs. These costs are aggregated and then allocated to specific customer project codes based on the Admin. Table in presented in request 3. below. The net balance in the Construction project codes will reflect whether administrative costs are set at correct amounts based on project volumes and hours charged.

See enclosed file for costs and approximate allocation values based on costs and estimated volumes.

2018CostbyCategoryPSDR.xlsx

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide support for the trigger for administrative charges indicated in the attached "NC/SC DEC and DEP Administrative Overhead and Commissioning Costs - July 2018 - Non-Fast Track (External Use)" (Costs Table).

**Response:**

See file enclosed for 2. above to support administrative charges.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

Please explain what is included in "direct-charged study costs" and "direct-charged construction costs" indicated in the Costs Table. Are these direct costs applied to the deposit, or billed directly to the interconnection customer?

**Response**:

Direct-charged study and construction costs are costs charged to Interconnection Customer-specific project codes by Distribution or Transmission employees/contractors who are doing either study or construction work on that specific Interconnection project. Time and expenses are tracked to specific projects and charged accordingly.

The labor and expenses are charged against study deposits (in 242 liability accounts on the Balance Sheet) or accumulated in project codes (in 107 asset accounts) for construction projects. Payments, whether study deposits or up-front payments for Interconnection Facilities and/or System or Network upgrades are then matched against the costs when true ups are completed.

Interconnection Customers generally pay either up-front or at true up. They do not normally receive bills during construction unless it becomes evident the scope of the project has changed and/or actual costs are known to be significantly exceeding estimates outlined in the Interconnection Agreement. (example DEP Bunn Level project required additional Interconnection payments as meeting tight deadline caused significant overtime). In DEC, payments for Interconnection Facilities are done on a monthly basis versus paid up-front, so total Interconnection Costs would be adjusted, thereby adjusting the monthly payment.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

If an interconnection customer's initial deposit is depleted through the application of study-related charges, do the Companies require the interconnection customer to replenish the deposit? If so, what amount do the Companies request for replenishment?

**Response**:

The Companies do not normally request replenishment of the deposit. If an initial deposit is depleted through the application of study-related charges, including overheads, the amount of under-recovery is requested in the true up with that customer. . The true up is conducted after the project receives a Permission to Operate unless the project withdraws and does not complete construction. This is either done pre-construction if the project is withdrawn/cancelled or post-construction after project receives Permission to Operate. The amount requested is the amount of under-recovery after taking study deposit received + up-front payments received for Interconnection Facilities plus System/Network Upgrades and subtracting total amount of direct charges, overheads and taxes.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

For at least two (2) interconnection requests that have recently been connected and made available for commercial operation, and which proceeded through the Section 4 Study Process, please provide an accounting of how the Interconnection Request Deposit was *actually* spent, with the amount (if any) deducted to cover application processing expenses clearly noted.

**Corrected Response:**

1. **[Begin Confidential]** [redacted] [redacted] **[End Confidential]** 4.998 MW AC PTO on 04/30/18

| | |
|---|---|
| **Deposit Received from Customer** | **($25,000.00)** |
| Admin Allocation to Cover Study-Recovered Work | $18,000.00 |
| Internal Labor Charged to Specific Customer Study Project Code | $9,527.36 |
| Contract Labor Charged to Specific Customer Study Project Code | $10,958.04 |
| Vehicle & Equip Chargeback Charged to Specific Customer Study Project Code | $178.63 |
| **Total Costs Incurred for Study Work** | **$38,664.03** |
| **Net Additional Amount Due from Customer for Study Work** | **$13,664.03** |

1. **[Begin Confidential]** [redacted] [redacted] **[End Confidential]** 4.998 MW AC PTO on 12/07/2017

| | |
|---|---|
| **Deposit Received from Customer** | **($24,998.00)** |
| Admin Allocation to Cover Study-Recovered Work | $18,000.00 |
| Internal Labor Charged to Specific Customer Study Project Code | $3,247.02 |
| Contract Labor Charged to Specific Customer Study Project Code | $19,444.88 |
| Vehicle & Equip Chargeback Charged to Specific Customer Study Project Code | $409.81 |
| **Total Costs Incurred for Study Work** | **$41,101.71** |
| **Net Additional Amount Due from Customer for Study Work** | **$16,103.71** |

NC Public Staff
Data Request No. 8
Docket No. E-100, Sub 101
NCIP
Item No. 8-7
Page 1 of 1



**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

Does Duke plan to continue billing for commissioning-related costs, or will responsibility for billing for these charges be transferred to Advanced Energy or other parties providing Commissioning services?

**Response**:

The Companies intended to transition the billing for commissioning related costs to Advanced Energy in early 2018, but elected to maintain billing for these services after further consideration. To perform the billing, Advanced Energy would need to establish billing and accounts for each project and account for the risk of non-payment by the interconnection customers. By maintaining responsibility for billing, The Companies also retain the ability to contract with other service providers if needed to perform the commissioning related services. In the near term, the Companies will continue to include the estimated commissioning costs in Interconnection Agreements and collect those funds as part of the upfront payments required under the Interconnection Agreement. Actual commissioning-related costs will be included in the true up process.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request**:

For 2017 and YTD 2018, please provide the total dollar value deducted from all Interconnection Request Deposits for each Company that was used specifically to cover application processing expenses, and not used for any other expenses.

**Response**:

The Companies are allocating costs charged to ICSTUDY based on the Admin. table file produced in response to Public Staff 8-3. above. We are not able to split out application processing expenses from other interconnection-related support expenses as we are aggregating costs by support provided as well as money received from Interconnection Customers. Estimated annualized 2018 expenses by category have been included in the Excel file enclosed in response 2 above. 2017 expenses would approximate those in 2018, but the cost methodology was rolled out in 4Q17. Some expenses were moved in 2017, but 2018 is the first year of full deployment.

NC Public Staff
Data Request No. 8
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Item No. 8-9




**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide an estimate for the amount of time (labor) required to process a single application in each project category noted on slide 7 of the fee proposal slide deck (pre-apps, <20 kW, <100 kW, <2 MW, change of control).

**Response:**

Time estimates gathered from discussions with and, if applicable, analysis by the Renewables Service Center, Distributed Generation, and DET Account Management/Customer Account Specialists.

TimeEstimateforFees.xlsx

## DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

**Request**:

Please provide how the Companies accounts for the following application processing expenses specified in the fee proposal slide deck (labor, PowerClerk, and Salesforce) by FERC account.

**Response**:

Employee labor, contractor and other relevant employee expenses included in the application processing expenses specified in the fee proposal slide deck is booked to project code ICREVIEW in account numbers 593, 408 and 926. The revenue for fees received is also included in the ICREVIEW project code, and the revenue is booked to account number 456.

Charges for use of PowerClerk (Clean Power Research) have historically been booked to account numbers 921.4 in 2017 and 923 in 2018.

Salesforce expenses are booked to account number 182.3 with related taxes and employee benefits booked to account number 408 and 920 level various account numbers, respectively. At the end of the year, the Salesforce expenses are moved via journal entry to account numbers 593 and 242 per an allocation process that splits the expense by jurisdiction, state and type of work supported.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Do the Companies believe that increasing the fee for Pre-Application reports from $300 to $500 will potentially reduce interconnection customers from seeking this information in advance of filing an interconnection request? Should this cost be pro-rated based on the size of the facility? If not, why.

**Response:**

The Companies do not anticipate that the proposed fee increase for Pre-Applications will reduce the number of customers requesting Pre-Application Reports. As part of a larger effort to improve communications and transparency, the Companies are already implementing changes to provide additional information about potential constraints or issues in Pre-Application Reports. To the extent known, the Companies plan to include information about existing LVR's, existing circuit voltage constraints, and other readily available information that can help interconnection customers assess proposed locations. These additions will add value to the Pre-Application reports.

The Companies did not propose to prorate the cost of Pre-Applications based on facility size. The cost of preparing the Pre-Application Report does not vary with size and the magnitude of the fee is not significant for the size of projects likely to benefit from requesting a Pre-Application Report.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Do the Companies believe that the information currently provided in the Pre-Application reports sufficiently helps interconnection customers accurately assess the feasibility of interconnecting at a particular location? How can this process be improved to help reduce the number of projects that proceed to the study phase that face significant interconnection constraints?

**Response:**

The technical capabilities of interconnection customers and/or their consultants is the primary factor impacting whether the pre-application might be considered "sufficient," in the eyes of those same interconnection customers. However, this factor is very difficult for Duke to assess as there is a wide range of technical experience amongst developers and consultants involved in interconnection requests in North Carolina. If a site is attempting to interconnect in a heavily penetrated area, this can usually be concluded relatively easily from the pre-application report, which reports information on total MW of DER on the substation, the substation capacity, and aggregate queued generation. In other words, in heavily penetrated areas, a lack of project feasibility can be relatively easily determined. In areas with lesser penetration, information such as distance from the substation can still be very useful, although admittedly relative in nature, as such data may have more meaning in proportion to the experience one has in either submitting or evaluating interconnection requests. There are functional limitations in attempting to demonstrate relative feasibility, which is ultimately what an interconnection customer is attempting to conclude from a pre-application report.

The scoping meeting is designed to be a better opportunity to dig a little deeper on the nature of the area of interconnection, even though this does require an interconnection request to be submitted. However, it does provide interconnection customers the ability to exit the queue very early in the process if it decides that a project's chances of feasibility are rather low.

The Companies do not see ways to improve the process within the NCIP beyond the structure of the pre-application report and the scoping meeting. The Company would be happy to consider education sessions, perhaps as part of the TSRG or even separately offered to large groups of developers, which could demonstrate how best to interpret the information in a pre-application report for the benefit of the entity considering submission of an interconnection request.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Pursuant to Section 6.1.2. of the standard interconnection agreement in the NCIP, does the Company issue all Interconnection Customers a final accounting report following the Interconnection Facilities Delivery Date, or only upon request? Do the Companies routinely comply with the 120 business day window to provide the Interconnection Customer with a final accounting report?

**Response:**

The Companies have been issuing final accounting reports for projects cancelling or withdrawing prior to entering the construction phase. This process was historically done upon request but in 1Q2018, the Company began issuing final accounting reports on a more consistent basis. The Companies have also begun issuing Interconnection Customers a final accounting report following completion of the commissioning tests for state jurisdictional distribution projects following completion of construction on state jurisdictional transmission projects. The Companies continue to make good faith efforts to comply with the 120 business-day window outlined in the NCIP, though charges can continue from outside vendors beyond the 120 business-day timeframe.

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide copies of three final accounting reports issued by the Companies in 2017 and 2018.

**Corrected Response:**

Per NCIP Attachment 9 section 6.1.2, the Companies are not required to issue final accounting reports unless requested by the Interconnection Customer in writing within 15 Business Days of the Interconnection Facilities Delivery Date or if implemented by the Utility. The Utility is in the process of formally implementing a final accounting reporting process because our analysis is revealing actual interconnection facility and system/network upgrade costs are significantly exceeding estimated costs included in the Interconnection Agreements. The Companies are working diligently to improve the estimating process, as well as ensuring estimates for commissioning costs and overhead costs are included in the estimated amounts in the current and future Interconnection Agreements.

Enclosed are three final accounting reports recently shared with Interconnection Customers.

**[Begin Confidential]**

[redacted] [redacted] [redacted]

**[End Confidential]**

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Please provide full copies of three state-jurisdictional interconnection agreements entered into between the Companies and Interconnection Customers in 2018, including all appendices and attachments.

**Corrected Response:**

Examples provided for transmission and distribution projects in DEC and DEP.

Redacted Attachment 1 - 2018 | Redacted Attachment 2 - 2018 | Redacted Attachment 3 - 2018

**DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC**

**Request:**

Section 6.1.3 of the standard interconnection agreement in the NCIP provides as follows:

The Utility shall also bill the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades, as set forth in Appendix 6 of this Agreement. The Utility shall bill the Interconnection Customer for the costs of providing the Utility's Interconnection Facilities including the costs for on-going operations, maintenance, repair and replacement of the Utility's Interconnection Facilities under a Utility rate schedule, tariff, rider or service regulation providing for extra facilities or additional facilities charges, as set forth in Appendix 2 of this Agreement, such monthly charges to continue throughout the entire life of the interconnection.

For the following questions related to ongoing O&M costs associated with Interconnection Facilities and Network Upgrades, please provide written responses or make Duke personnel available for a meeting or conference call to discuss the following questions:

a. Do the Companies believe that the current Monthly Interconnection Facilities Charge is appropriate to cover the costs of operating and maintaining the interconnection facilities as well as the costs associated with operating, maintaining, repairing and replacing the Utility's transmission and distribution grid for the life of the generating facility? If yes, please explain why.

b. Do the Companies anticipate changing the Monthly Interconnection Facilities Charge percentage going forward?

c. Please provide the basis for how the Company "bills the Interconnection Customer for the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades." How is this cost calculated, and how is it billed?

d. Do the Companies believe that the charges discussed in question c above are appropriate to cover the ongoing / lifetime costs of operating and maintaining the system upgrades for the life of the generating facility? If the response is no, then please explain how the Companies propose to recover these ongoing costs after the interconnection of the QF is completed.

**Response**:

a. Yes. The carrying charge rate is reviewed in every general rate case to validate that it adequately recovers the full revenue requirement associated with the installation of distribution and transmission assets. The rate was recently reviewed and adjusted for DEP effective March 16, 2018 and for DEC effective August 1, 2018 in their respective general rate cases. Any adjustment of the carrying charge rate impacts both existing and new sellers with Interconnection Facilities thereby ensuring adequate cost recovery as conditions change over time. The Monthly Interconnection Facilities Charges are billed to Interconnection Customers monthly for the duration of the Interconnection Agreement.

   Interconnection Customers generally pay upfront the costs of interconnection-required system and network upgrades that are deemed to benefit the service area even though they are specifically being installed to meet the immediate needs of the interconnecting seller. The up-front payment is considered to be a contribution-in-aid-of-construction under the Distribution Line Extension Plan (LEP) and is booked as a reduction to rate base. As with all other assets installed under the LEP, the cost of maintaining the line is considered a normal cost of doing business and is recovered in general retail rates from all customers. If the network upgrade is deemed to be solely for the use and benefit of the interconnection seller, then it would be treated as all other Interconnection Facilities with the seller paying a monthly charge.

b. The assets installed to interconnect a QF are similar to facilities installed to provide retail service; therefore, the Company believes standard approaches reflected in the Extra Facilities Plan continue to apply. We will continue to review this as we analyze the impacts of distributed generation on the grid to assess whether additional charges are appropriate, but we believe the present approach to the provision of network upgrades and interconnection facilities is appropriate. There is no current plan to change the Monthly Interconnection Facilities Charge percentage outside of the normal process whereby the percentage is revised as part of updates to Service Regulations and Terms and Conditions for the Purchase of Electric Power for each of the Companies.

c. See also response to 16. a. above. Under the Interconnection Facilities process, the Company fully recovers the revenue requirement with the installation of the assets. When the facilities are deemed to not only benefit the requesting seller, but also will provide enhanced service availability to surrounding retail customers, the costs associated with operating, maintaining, repairing and replacing the Utility's System Upgrades are considered to be a general cost of providing electric service to the area, with the cost of installing the asset being fully borne by the QF requesting the interconnection.

d. The Companies are tracking ongoing account management and technical support costs that occur after construction is complete and Interconnection Facilities are fully tested and commercially operable. There is no current rate in place to charge Interconnection Customers for these types of support costs. Also, ongoing specific testing/studies required to be done on interconnection facilities as they age, are damaged, or are impacted by ongoing technological improvements will need to be assessed and potentially charged back to the Interconnection Customers. The Companies plan is evaluating ancillary and integration services cost to decide if they should be included in the Administrative Seller Charge or through a new monthly fixed or volumetric rate that would allow these costs to be recovered from sellers served under Purchased Power Agreements.

I/0014
A/0015



Exhibit SBA-Direct-10

Pacific Gas and Electric Company®

**Erik Jacobson**
Director
Regulatory Relations

Pacific Gas and Electric Company
77 Beale St., Mail Code B13U
P.O. Box 770000
San Francisco, CA 94177

Fax: 415-973-3582



September 19, 2017

**Advice 5143-E**
(Pacific Gas and Electric Company ID U 39 E)

Public Utilities Commission of the State of California

**Subject:** **Information-Only Filing Regarding Net Energy Metering (NEM) Costs**

## Purpose

Pacific Gas and Electric Company (PG&E) hereby submits via an Information-only filing a report on interconnection costs for all Net Energy Metering (NEM) customers in compliance with Decision (D.) 16-01-044.[1] This filing covers the period of August 2016 through August 2017.

## Background

D.16-01-044 authorized the investor-owned utilities (IOUs) to collect a one-time application fee for NEM successor tariff customers with systems smaller than 1 megawatt (MW), to allow the utility to recover the costs of providing the interconnection service from the customers benefitting from the interconnections[2]. The fee for each IOU must be based on the interconnection costs shown in each IOU's June 2015 advice letter[3], filed in accordance with D.14-05-033 and Resolution E-4610.

D.16-01-044 required each IOU to continue to report its interconnection costs in accordance with the directions in D.14-05-033 and Resolution E-4610. After discussion with Energy Division, it was determined that the IOUs shall submit this report yearly on

[1] D.16-01-044, p. 88, provides in pertinent part: "Because costs may change over time, each IOU must continue to report its interconnection costs in accordance with the directions in D.14-05-033 and Res. E-4610."

[2] D.16-01-044 at pp.87-88. Note that Single-family Affordable Solar Housing (SASH) customers are exempted from this interconnection fee.

[3] PG&E filed Advice 4660-E on June 30, 2015 (approved December 31, 2015). PG&E filed a subsequent advice letter, Advice 4847-E, on May 25, 2016 (approved January 9, 2017) to correct costs that were inadvertently omitted.

September 19[4]. This report contains data from August 2016 through August 2017. Next year's report will contain data from September2017 through July 2018.

**Net Energy Metering Interconnection Costs**

The report of interconnection costs for all NEM customers from August 1, 2016 through August 31, 2017 is attached to this Advice Letter, Attachment A.

The filing would not increase any current rate or charge, cause the withdrawal of service, or conflict with any rate schedule or rule.

**Protests**

This is an information-only advice letter filing. Pursuant to General Order 96-B Section 6.2, PG&E is not seeking relief through this advice letter and is not subject to protest. Instead, PG&E is simply reporting the interconnection costs for all NEM customers pursuant to D.16-01-044.

**Effective Date**

PG&E requests that this information-only advice filing become effective September 19, 2017, the date of filing.

**Notice**

In accordance with General Order 96-B, Section IV, a copy of this advice letter is being sent electronically and via U.S. mail to parties shown on the attached list and the parties on the service lists for R.12-11-005 and R.14-07-002. Address changes to the General Order 96-B service list should be directed to PG&E at email address PGETariffs@pge.com. For changes to any other service list, please contact the Commission's Process Office at (415) 703-2021 or at Process_Office@cpuc.ca.gov. Send all electronic approvals to PGETariffs@pge.com. Advice letter filings can also be accessed electronically at: http://www.pge.com/tariffs/.

/S/

Erik Jacobson
Director, Regulatory Relations

Attachments

cc: Service Lists R.12-11-005 and R.14-07-002

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[4] Or the next business day, should September 19 fall on a weekend or holiday (Rule 1.15 Computation of Time California Public Utilities Commission Rules of Practice and Procedure)

# CALIFORNIA PUBLIC UTILITIES COMMISSION

## ADVICE LETTER FILING SUMMARY
## ENERGY UTILITY



MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. **Pacific Gas and Electric Company (ID U39 E)**

| Utility type: | Contact Person: Kingsley Cheng |
|---|---|
| ☑ ELC ☐ GAS | Phone #: (415) 973-5265 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: k2c0@pge.com and PGETariffs@pge.com |

| EXPLANATION OF UTILITY TYPE | (Date Filed/ Received Stamp by CPUC) |
|---|---|
| ELC = Electric GAS = Gas<br>PLC = Pipeline HEAT = Heat WATER = Water | |

Advice Letter (AL) #: 5143-E Tier: N/A

Subject of AL: **Information-Only Filing Regarding Net Energy Metering (NEM) Costs**

Keywords (choose from CPUC listing): Compliance

AL filing type: ☑ Monthly ☐ Quarterly ☐ Annual ☐ One-Time ☐ Other ____________

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #: D.16-01-044

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: No

Summarize differences between the AL and the prior withdrawn or rejected AL: ____________

Is AL requesting confidential treatment? If so, what information is the utility seeking confidential treatment for: No

Confidential information will be made available to those who have executed a nondisclosure agreement: N/A

Name(s) and contact information of the person(s) who will provide the nondisclosure agreement and access to the confidential information: ____________

Resolution Required? ☐Yes ☑No

Requested effective date: **September 19, 2017** No. of tariff sheets: N/A

Estimated system annual revenue effect (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed: N/A

Pending advice letters that revise the same tariff sheets: N/A

This is an information-only advice letter filing. Pursuant to General Order 96-B Section 6.2, PG&E is not seeking relief through this advice letter and is not subject to protest.

**California Public Utilities Commission**
**Energy Division**
**EDTariffUnit**
**505 Van Ness Ave., 4th Flr.**
**San Francisco, CA 94102**
**E-mail: EDTariffUnit@cpuc.ca.gov**

**Pacific Gas and Electric Company**
**Attn: Erik Jacobson**
**Director, Regulatory Relations**
**c/o Megan Lawson**
**77 Beale Street, Mail Code B13U**
**P.O. Box 770000**
**San Francisco, CA 94177**
**E-mail: PGETariffs@pge.com**

## Attachment A
## NEM Interconnection Costs

In response to the California Public Utilities Commission (CPUC) order stated in Decision (D) 16-01-044, PG&E has tracked the following interconnection costs (Tables 1-5) related to its Net Energy Metering tariffs for the period August 1, 2016 through August 31, 2017. PG&E's current available NEM tariffs include: Schedules NEM (including NEMA and NEMMT), NEMFC, NEMV, NEMVMASH and NEM 2.

**Note:** The figures included in this report are based on historic interconnection records. They represent the cost of interconnection between the dates of August 1, 2016 and August 31, 2017 as a result of existing interconnection processes and requirements. As such, any attempts to use these figures to forecast future interconnection costs should account for changes to processes, requirements/ standards, and changes in capacity of interconnected distributed energy resources relative to the local integration capacity of the circuit.

| | |
|---|---|
| [illegible] | 71,010 |
| [illegible] | 68,449 |

| Table 1<br>Processing/Administration Costs | |
|---|---|
| Total | $5,714,701 |
| Note: Includes Application Processing (e.g., validating single line diagram, interconnection agreement, electrical inspection clearance from governmental agency having jurisdiction, and other required documents), and back office tasks (e.g., initial billing setup). | |

| Table 2<br>Distribution Engineering Costs | |
|---|---|
| Total | $1,306,596 |
| Note: Includes technical analysis, studies, and screens consistent with Rule 21 (e.g., voltage rise, 15% Penetration, transformer loading) | |

| Table 3<br>Meter Installation/Inspection and Commissioning | |
|---|---|
| Total | $262,674 |
| Note: Includes residential and non-residential meter changes and remote meter programming, material, suppplies, procurement costs, labor for installation, testing, engineering, and quality assurance necessary for interconnection | |

| Table 4<br>Facility Upgrade Costs | |
|---|---|
| Type | Total |
| Interconnection Facilities | $4,882,328 |
| Distribution Upgrades | $11,226,192 |
| Total | $16,108,520 |

In response to the CPUC order stated in Decision (D) 16-01-044, PG&E has tracked the following waived fees and costs (Table 5) related to interconnection of NEM-Paired Storage for the period of August 1, 2016 through August 31, 2017.

| Table 5<br>NEM-Paired Storage Waived Fees and Costs | | |
|---|---|---|
| Category | Number of Projects | Total Cost |
| Application Fee | 72 | $57,600 |
| Supplemental Review Fee | 6 | $15,000 |
| Distribution Upgrades | 0 | $0 |
| Standby Charges | 191 | $210,203 |
| NGOM Metering | 175 | $159,359 |
| Notes: | | |
| • Application Fee calulcated for NEM-Paired Storage from August 1, 2016 until the December 15, 2016 (PG&E NEM Cap Date). All NEM-Paired Storage applications received, under the NEM 2 Tariff, have been subject to the $145 Application fee.<br>• Standby Charges calculated according to Schedule S for customers interconnected at distribution level. PG&E understands that there can be reactive demand impacts from inverter based customer-storage units without reactive power compensation; however since most of these customers do not have a meter capable of measuring VARs, the reactive demand charges will be tracked as $0.00. | | |

**PG&E Gas and Electric**
**Advice Filing List**
**General Order 96-B, Section IV**

AT&T
Albion Power Company
Alcantar & Kahl LLP
Anderson & Poole
Atlas ReFuel

BART
Barkovich & Yap, Inc.
Braun Blaising McLaughlin & Smith, P.C.
Braun Blaising McLaughlin, P.C.

CENERGY POWER
CPUC
CalCom Solar
California Cotton Ginners & Growers Assn
California Energy Commission
California Public Utilities Commission

California State Association of Counties
Calpine
Casner, Steve
Center for Biological Diversity
City of Palo Alto

City of San Jose
Clean Power
Clean Power Research
Coast Economic Consulting
Commercial Energy
Cool Earth Solar, Inc.
County of Tehama - Department of Public Works
Crossborder Energy
Crown Road Energy, LLC
Davis Wright Tremaine LLP
Day Carter Murphy

Defense Energy Support Center
Dept of General Services
Division of Ratepayer Advocates

Don Pickett & Associates, Inc.
Douglass & Liddell
Downey & Brand
Ellison Schneider & Harris LLP
Energy Management Services
Evaluation + Strategy for Social Innovation

G. A. Krause & Assoc.
GenOn Energy Inc.

Goodin, MacBride, Squeri, Schlotz & Ritchie
Green Charge Networks
Green Power Institute
Hanna & Morton
ICF
International Power Technology
Intestate Gas Services, Inc.

Kelly Group
Ken Bohn Consulting
Leviton Manufacturing Co., Inc.
Linde
Los Angeles County Integrated Waste Management Task Force
Los Angeles Dept of Water & Power
MRW & Associates
Manatt Phelps Phillips
Marin Energy Authority
McKenna Long & Aldridge LLP
McKenzie & Associates
Modesto Irrigation District

Morgan Stanley
NLine Energy, Inc.
NRG Solar
Nexant, Inc.
ORA
Office of Ratepayer Advocates
Office of Ratepayer Advocates, Electricity Planning and Policy B

OnGrid Solar
Pacific Gas and Electric Company
Praxair
Regulatory & Cogeneration Service, Inc.
SCD Energy Solutions

SCE
SDG&E and SoCalGas
SPURR
San Francisco Water Power and Sewer

Seattle City Light
Sempra Energy (Socal Gas)
Sempra Utilities
SoCalGas
Southern California Edison Company
Southern California Gas Company (SoCalGas)
Spark Energy
Sun Light & Power
Sunshine Design
Tecogen, Inc.
TerraVerde Renewable Partners

TerraVerde Renewable Partners, LLC
Tiger Natural Gas, Inc.
TransCanada
Troutman Sanders LLP
Utility Cost Management
Utility Power Solutions
Utility Specialists

Verizon
Water and Energy Consulting
Wellhead Electric Company
Western Manufactured Housing Communities Association (WMA)
YEP Energy
Yelp Energy

SOUTHERN CALIFORNIA
EDISON
An EDISON INTERNATIONAL® Company

**Russell G. Worden**
Managing Director, State Regulatory Operations



September 19, 2017

**ADVICE 3658-E**
**(U 338-E)**

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

**SUBJECT:** Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs

## PURPOSE

Pursuant to California Public Utilities Commission (Commission or CPUC) Decision (D.)16-01-044, Southern California Edison Company (SCE) respectfully submits this information-only Advice Letter (AL) to report the costs of interconnection for all Net Energy Metering (NEM) customers for the period covering August 1, 2016 through July 31, 2017.

## BACKGROUND AND DISCUSSION

On February 5, 2016, the Commission issued D.16-01-044 to adopt a successor to the NEM tariff and adopt standardized interconnection fees for NEM customers installing systems sized 1 megawatt (MW) and smaller. D.16-01-044 required that each Investor-Owned Utility's (IOU's) fee must be based on the interconnection costs shown in each IOU's June 2015 advice letter, filed in accordance with D.14-05-033 and Resolution E-4610. Due to interconnection costs changing over time, D.16-01-044 required each IOU to continue to report its interconnection costs in accordance with the directions in D.14-05-033 and Resolution E-4610.[1] In compliance with D.16-01-044, SCE hereby submits this update to its NEM interconnection cost report, which is included as Attachment A to this advice filing and includes interconnection costs for the period covering August 1, 2016 through July 31, 2017. Subsequent updates will be filed annually on September 19 of each year.

1 D.16-01-044 p. 88.

## TIER DESIGNATION

Pursuant to General Order (GO) 96-B, Energy Industry Rule 5.1, this advice letter is submitted with a Tier 1 designation.

## PROTESTS

In accordance with GO 96-B, Section 6.2, this information-only advice filing is not subject to protest.

## NOTICE

In accordance with General Rule 4 of GO 96-B, Ordering Paragraph (OP) 4 of Resolution E-4610, and OP 16 of D.14-05-033, and page 88 of D.16-01-044, SCE is serving copies of this advice filing to the interested parties shown on the attached service lists for GO 96-B, R.12-11-005 and R.14-07-002. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at 626-302-4039. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with the Public Utilities Code Section 491, notice to the public is hereby given by filing and keeping the advice filing at SCE's corporate headquarters. To view other SCE advice letters filed with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Kathy Wong at (626) 302-2327 or by electronic mail at Kathy.Wong@sce.com.

**Southern California Edison Company**

/s/ Russell G. Worden
Russell G. Worden

RGW:kw:jm
Enclosure

# ATTACHMENT A
# SCE ADVICE 3658-E
# REPORT OF SOUTHERN CALIFORNIA EDISON COMPANY REGARDING NET ENERGY METERING INTERCONNECTION COSTS PURSUANT TO DECISION 16-01-044

## I. NEM Interconnection Costs

Tables 1 through 4 below show the costs related to the interconnection of eligible Net Energy Metering (NEM) generating facilities under SCE's NEM tariffs, namely, Schedules NEM, MASH-VNM, NEM-V, and FC-NEM. The amounts shown represent the actual NEM interconnection costs tracked and recorded from August 1, 2016 through July 31, 2017.

**Table 1**
**NEM Processing and Administration Costs**

| Category | Total Costs |
|---|---|
| Application Processing and Administration | $1,845,630 |

Note:

• Includes application processing (e.g., validating and approving single line diagram, interconnection agreement, electrical inspection clearance from governmental agency having jurisdiction, and other required documents), and back office tasks (e.g., initial billing setup), inquiry calls and emails, and permit-to-operate (PTO) mailer.

• The total cost is based on processing and administering:
- *51,660* new applications (i.e. applications from customers or contractors)
- *17,333* resubmitted applications with corrections and/or additional documents
- *10,776* Equipment changes
- *47,230* PTO

• Management and administration time is included in the cost.

| Table 2<br>Distribution Engineering Costs | | |
|---|---|---|
| **Category** | **Number of projects** | **Total Costs** |
| In-Office Review | 6,237 | $230,995 |

Note:
- Includes technical analysis, studies, and screens consistent with Rule 21 (e.g., voltage rise, 15 percent penetration, transformer loading.
- Management and administration time are included in the cost.

| Table 3<br>Metering Installation/Inspection and Commissioning Costs | | |
|---|---|---|
| **Category** | **Number of projects** | **Total Costs** |
| Meter Change | 1,805 | $208,035 |
| Remote Meter Programming | 62,419 | $1,260 |
| Inspection and Commissioning | 678 | $47,767 |

Note:
- Includes residential and non-residential meter changes, remote meter programming, material, supplies, procurement costs, labor for installation, testing, engineering, and quality assurance necessary for interconnection.

| Table 4<br>Facility Upgrade Costs | | |
|---|---|---|
| **Category** | **Number of projects** | **Total Costs** |
| Interconnection Facilities | 5,670 | $2,507,254 |
| Distribution Upgrades | 125 | $4,690,416 |

Note:
- Interconnection facility costs include material and labor charges and are comprised of costs paid by NEM customers and costs not paid by NEM customers.
- Distribution upgrade costs include material and labor charges paid and not paid by NEM 1.0 and NEM 2.0 customers.
- NEM Paired Storage Complex Metering Costs are included. For a detailed breakdown of these costs from January 1 through July 31, 2017 please refer to Table 7.

## II. Interconnection Fees Waived

Table 5 below shows the waived fees associated with interconnecting qualifying NEM-paired storage systems. The amounts shown represent the waived fees from August 1, 2016 through July 31, 2017.

| Table 5<br>Waived Interconnection Fees for Qualifying NEM-Paired Storage System | | |
|---|---|---|
| **Category** | **Number of projects** | **Total Costs** |
| Interconnection Application | 329 | $263,200 |
| Supplemental Review | 0 | $0 |
| Distribution Upgrade | 0 | $0 |
| Standby | n/a | n/a |
| NGOM | 6 | $498 |

Note:
- Current SCE policy is to not charge Standby for NEM-paired storage system.

## III. Interconnection Costs Refunded

In Advice 3062-E et al., the IOUs requested to track and report the interconnection costs refunded to customers who paid to interconnect qualifying NEM-paired storage systems prior to the issuance of D.14-05-033. The request was approved and, as such, Table 6 below shows the interconnection costs refunded by SCE to its customers with qualifying NEM-paired storage systems from August 1, 2016 through July 31, 2017.

| Table 6<br>Refunded Interconnection Costs Qualifying NEM-Paired Storage System | | |
|---|---|---|
| **Category** | **Number of projects** | **Total Costs** |
| Interconnection Application | 0 | $0 |
| NGOM | 0 | $0 |

## IV. NEM Paired Storage Complex Metering Costs

Table 7 below shows the metering costs associated with NEM Paired Storage Complex Meters. The amounts shown represent complex metering costs for systems from January 1, 2017 through July 31, 2017.

| Table 7<br>NEM Paired Storage Complex Metering Costs | |
|---|---|
| **Invoice Category** | **Total Costs** |
| Labor | $14,338 |
| Material | $9,463 |
| ITCC | $5,236 |
| Other (Ownership Cost) | $8,412 |
| **Grand Total** | **$37,450** |

Note:
•Total costs are for 12 NEM-PS complex metering projects

# CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY



| MUST BE COMPLETED BY UTILITY (Attach additional pages as needed) | |
|---|---|
| Company name/CPUC Utility No.: Southern California Edison Company (U 338-E) | |
| Utility type:<br>☑ ELC ☐ GAS<br>☐ PLC ☐ HEAT ☐ WATER | Contact Person: Darrah Morgan<br>Phone #: (626) 302-2086<br>E-mail: Darrah.Morgan@sce.com<br>E-mail Disposition Notice to: AdviceTariffManager@sce.com |
| EXPLANATION OF UTILITY TYPE<br>ELC = Electric GAS = Gas<br>PLC = Pipeline HEAT = Heat WATER = Water | (Date Filed/ Received Stamp by CPUC) |

Advice Letter (AL) #: 3658-E Tier Designation: 1

Subject of AL: Information-Only Advice Letter, Southern California Edison Company's Report on Net Energy Metering Interconnection Costs

Keywords (choose from CPUC listing): Compliance, Metering

AL filing type: ☑ Monthly ☐ Quarterly ☐ Annual ☐ One-Time ☐ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:

Decision 16-01-044

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? ☐ Yes ☑ No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement.
Name and contact information to request nondisclosure agreement/access to confidential information:

Resolution Required? ☐ Yes ☑ No

Requested effective date: N/A No. of tariff sheets: -0-

Estimated system annual revenue effect: (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: None

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: None

[1] Discuss in AL if more space is needed.

**All correspondence regarding this AL filing shall be sent to:**

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Ave.,
San Francisco, CA 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Russell G. Worden
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Telephone: (626) 302-4177
Facsimile: (626) 302-6396
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

SDGE

A Sempra Energy utility®

Clay Faber - Director
Federal & CA Regulatory
8330 Century Park Court
San Diego, CA 92123

cfaber@semprautilities.com

October 12, 2017

**ADVICE LETTER 3131-E**
(U902-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

**SUBJECT: INFORMATION ONLY FILING REGARDING NET ENERGY METERING (NEM) COSTS**

San Diego Gas & Electric Company (SDG&E) hereby submits to the California Public Utilities Commission (Commission) an Information-only report on interconnection costs for all Net Energy Metering (NEM) customers in compliance with Decision (D.) 16-01-044. This filing covers the period of August 1, 2016 through July 31, 2017.

**BACKGROUND**

On February 5th, 2016, the Commission issued D.16-01-044 that authorized investor-owned utilities (IOUs) to collect a one-time application fee for NEM successor tariff customers with systems smaller than 1 megawatt (MW), to allow the utility to recover the costs of providing the interconnection service from the customers benefitting from the interconnections.[1] The fee for each IOU must be based on the interconnection costs shown in each IOU's June 2015 advice letter[2], filed in accordance with D.14-05-033 and Resolution E-4610.

D.16-01-044 required each IOU to continue to report its interconnection costs in accordance with the directions in D.14-05-033 and Resolution E-4610.[3] This report contains data from August 1, 2016 through July 31, 2017 and is included in this filing as Attachment A.

**EFFECTIVE DATE**

This filing is subject to Energy Division disposition and is classified as Tier 1 (effective pending disposition) pursuant to GO 96-B. SDG&E respectfully requests that this filing become effective on October 12, 2017, which is the date of this filing.

**PROTEST**

In accordance with GO 96-B Section 6.2, this information-only filing is not subject to protest.

---

[1] D.16-01-044, pp.87-88.
[2] SDG&E filed Advice Letter 2761-E on June 30, 2015 (approved on December 31, 2015).
[3] D.16-01-044 at p. 88.

**NOTICE**

A copy of this filing has been served on the utilities and interested parties shown on the attached list, including interested parties in R.12-11-005 and R.14-07-002, by providing them a copy hereof either electronically or via the U.S. mail, properly stamped and addressed.

Address changes should be directed to SDG&E Tariffs by email to SDG&ETariffs@semprautilities.com.

CLAY FABER
Director – Regulatory Affairs

# CALIFORNIA PUBLIC UTILITIES COMMISSION

ADVICE LETTER FILING SUMMARY
ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No. SAN DIEGO GAS & ELECTRIC (U 902)

| Utility type: | Contact Person: Joff Morales |
|---|---|
| ☒ ELC ☐ GAS | Phone #: (858) 650-4098 |
| ☐ PLC ☐ HEAT ☐ WATER | E-mail: jmorales@semprautilities.com |

| EXPLANATION OF UTILITY TYPE | (Date Filed/ Received Stamp by CPUC) |
|---|---|
| ELC = Electric GAS = Gas | |
| PLC = Pipeline HEAT = Heat WATER = Water | |

Advice Letter (AL) #: 3131-E

Subject of AL: Information Only Filing Regarding Net Energy Metering (NEM) Costs

Keywords (choose from CPUC listing): NEM

AL filing type: ☐ Monthly ☐ Quarterly ☐ Annual ☐ One-Time ☒ Other

If AL filed in compliance with a Commission order, indicate relevant Decision/Resolution #:
D.16-01-044

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL: N/A

Summarize differences between the AL and the prior withdrawn or rejected AL[1]: N/A

Does AL request confidential treatment? If so, provide explanation:

Resolution Required? ☐ Yes ☒ No Tier Designation: ☒ 1 ☐ 2 ☐ 3

Requested effective date: 10/12/2017 No. of tariff sheets: 0

Estimated system annual revenue effect: (%): N/A

Estimated system average rate effect (%): N/A

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: N/A

Service affected and changes proposed[1]: N/A

Pending advice letters that revise the same tariff sheets: N/A

**Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this filing, unless otherwise authorized by the Commission, and shall be sent to:**

| | |
|---|---|
| **CPUC, Energy Division** | **San Diego Gas & Electric** |
| **Attention: Tariff Unit** | **Attention: Megan Caulson** |
| **505 Van Ness Ave.,** | **8330 Century Park Ct., CP 32F** |
| **San Francisco, CA 94102** | **San Diego, CA 92123** |
| **EDTariffUnit@cpuc.ca.gov** | **MCaulson@semprautilities.com** |

General Order No. 96-B
ADVICE LETTER FILING MAILING LIST

cc: (w/enclosures)

Public Utilities Commission
DRA
R. Pocta
Energy Division
M. Ghadessi
M. Salinas
Tariff Unit
CA. Energy Commission
F. DeLeon
R. Tavares
Alcantar & Kahl LLP
K. Cameron
American Energy Institute
C. King
APS Energy Services
J. Schenk
BP Energy Company
J. Zaiontz
Barkovich & Yap, Inc.
B. Barkovich
Bartle Wells Associates
R. Schmidt
Braun & Blaising, P.C.
S. Blaising
California Energy Markets
S. O'Donnell
C. Sweet
California Farm Bureau Federation
K. Mills
California Wind Energy
N. Rader
Children's Hospital & Health Center
T. Jacoby
City of Poway
R. Willcox
City of San Diego
J. Cervantes
G. Lonergan
M. Valerio
Commerce Energy Group
V. Gan
CP Kelco
A. Friedl
Davis Wright Tremaine, LLP
E. O'Neill
J. Pau
Dept. of General Services
H. Nanjo
M. Clark

Douglass & Liddell
D. Douglass
D. Liddell
G. Klatt
Duke Energy North America
M. Gillette
Dynegy, Inc.
J. Paul
Ellison Schneider & Harris LLP
E. Janssen
Energy Policy Initiatives Center (USD)
S. Anders
Energy Price Solutions
A. Scott
Energy Strategies, Inc.
K. Campbell
M. Scanlan
Goodin, MacBride, Squeri, Ritchie & Day
B. Cragg
J. Heather Patrick
J. Squeri
Goodrich Aerostructures Group
M. Harrington
Hanna and Morton LLP
N. Pedersen
Itsa-North America
L. Belew
J.B.S. Energy
J. Nahigian
Luce, Forward, Hamilton & Scripps LLP
J. Leslie
Manatt, Phelps & Phillips LLP
D. Huard
R. Keen
Matthew V. Brady & Associates
M. Brady
Modesto Irrigation District
C. Mayer
Morrison & Foerster LLP
P. Hanschen
MRW & Associates
D. Richardson
Pacific Gas & Electric Co.
J. Clark
M. Huffman
S. Lawrie
E. Lucha
Pacific Utility Audit, Inc.
E. Kelly
San Diego Regional Energy Office
S. Freedman
J. Porter
School Project for Utility Rate Reduction
M. Rochman
Shute, Mihaly & Weinberger LLP
O. Armi
Solar Turbines
F. Chiang

Southern California Edison Co.
M. Alexander
K. Cini
K. Gansecki
H. Romero
TransCanada
R. Hunter
D. White
TURN
M. Florio
M. Hawiger
UCAN
D. Kelly
U.S. Dept. of the Navy
K. Davoodi
N. Furuta
L. DeLacruz
Utility Specialists, Southwest, Inc.
D. Koser
Western Manufactured Housing
Communities Association
S. Dey
White & Case LLP
L. Cottle
Interested Parties
R.12-11-005
R.14-07-002

San Diego Gas & Electric Advice Letter 3131-E
October 12, 2017





# ATTACHMENT A

ATTACHMENT A

SDG&E AL 3131-E

REPORT OF SAN DIEGO GAS & ELECTRIC REGARDING NET ENERGY METERING INTERCONNECTION COSTS PURSUANT TO E-4610, D.14-05-033 AND D.16-01-044

Applicable for Schedule NEM {standard (<10kW), NEM Expanded (>10kW)}, MASH-VNM, NEM-V and FC-NEM (Fuel Cell), NEM Aggregation, NEM MT, and NEM MT-Storage

The overall costs of NEM are not limited to the interconnection costs that the Commission ordered the IOUs to track and report. The overall costs of NEM also include ongoing billing services, customer contact center costs in responding to customer inquiries on NEM bills, and other administration costs necessary in offering NEM.

## I. NEM Interconnection Costs

Pursuant to the California Public Utilities Commission's (Commission) order in Resolution E-4610, Tables 1 through 4 below show the costs related to the interconnection of eligible Net Energy Metering (NEM) generating facilities under SDG&E's NEM tariffs, namely, Schedules NEM, VNM-A, NEM-V, and NEM-FC. The amounts shown represent the NEM interconnection costs tracked and recorded from August 1, 2016 through July 31, 2017.

| Table 1<br>Processing/Administration Expenditures (1) | | | | | | | | Total Processing and Administration Costs |
|---|---|---|---|---|---|---|---|---|
| Category | # of NEW Applications | # of New Construction Batch Projects | # of Resubmittals Corrections/ Add Docmts | # of Final Inspections | # of Interconnect Agreements | # of PTO issued | Total Received | |
| Application Processing (1) | 20,820 | 396 | 0 | 5,366 | N/A | 19793 | 20,820 | $ 2,116,009 |

(1) Includes Application Processing (e.g., validating and approving single line diagram, interconnection agreement, electrical inspection clearance from governmental agency having jurisdiction, and other required documents), and back office tasks (e.g., initial billing setup), inquiry calls and emails. PTO's are issued within the application processing step, not an extra step.

ATTACHMENT A
SDG&E AL 3131-E

| Table 2 | | |
|---|---|---|
| Distribution Engineering Cost (1) | | |
| Category | # of projects | Total Cost |
| In-office Review (1) | 926 | **$52,068** |
| (1) Single Line Diagram, Includes technical analysis, studies, and screens consistent with Rule 21 (e.g., voltage rise, 15% Penetration, transformer loading) | | |

| Table 3 | | |
|---|---|---|
| Metering Installation/Inspection and Commissioning | | |
| Category | # of projects | Total Cost |
| Remote Meter Programming/Meter Change | 19,793 | **$6,865** |
| NEM Field Inspections | 5,366 | **$453,234** |
| (1) Includes residential and non-residential meter changes and remote meter programming, material, suppplies, procurement costs, labor for installation, testing, engineering, and quality assurance necessary for interconnection. | | |

| Table 4 | | |
|---|---|---|
| Facility/Upgrade Costs (1) | | |
| Category | # of projects | Total Cost |
| Interconnection Facilities | 0 | **$0.00** |
| Distribution Upgrades | | **$99,825.78** |
| (1)Includes Interconnection Facilities (some cost paid by customer) and Distribution Upgrades (cost paid by non-NEM customers) | | |

ATTACHMENT A
SDG&E AL 3131-E

## II. Interconnection Fees Waived

Table 5 below shows the waived fees associated with interconnecting qualifying NEM-paired storage system and supplemental review costs for NEM-paired and NGOM projects. The amounts shown represent the waived fees and costs from August 1, 2016 through July 31, 2017.

| Table 5 | | |
|---|---|---|
| Waived Fees and Costs (1) | | |
| Category | # of projects | Total Cost |
| Interconnection application fees | 0 | $0 |
| Supplemental review fees | 78 | **$4,386** |
| Distribution upgrade fees | 0 | $0 |
| Standby charges | 0 | $0 |
| NGOM Metering | 55 | **$12,370** |
| Refunded Interconnection Application fees | 0 | $0 |
| Refunded NGOM Metering fees | 0 | $0 |
| *Supervisor/Management time is not included in costs | | |

## III. Interconnection Cost Refunded

The IOUs requested to track and report the interconnection costs refunded to customers who paid to interconnect qualifying NEM-paired storage systems prior to the issuance of D.14-05-033. The request was approved and, as such, Table 6 below shows the interconnection costs refunded by SDG&E to its customer with qualifying NEM-paired storage systems from August 1, 2016 through July 31, 2017.

| Table 6 | | |
|---|---|---|
| Refunded Interconnection Costs For Qualifying NEM-Paired Storage System | | |
| Category | Number of Projects | Total Costs Refunded |
| Interconnection Application | 0 | $0 |
| NGOM | 0 | $0 |

Note: The difference in Number of Projects between Tables 5 and 6 reflect SDG&E's implementation of D.14-05-033

| | |
|---|---|
| **Total Application Steps** | **20,820** |
| **Total Application Costs less Waived Fees** | **$2,744,758** |
| | |
| **Cost per Application Step** | **$131.83** |

I/vol.4
A/0015



# Exhibit SBA-Rebuttal-1

NORTH CAROLINA

INTERCONNECTION PROCEDURES,
FORMS, AND AGREEMENTS

**For State-Jurisdictional Generator Interconnections**

Excerpts from
IREC Proposed
Revisions 1/8/2018
~~Effective 5/15/2015~~

Docket No. E-100, Sub 101

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 The 2015 revisions to the Commission's interconnection standard shall not apply to Generating Facilities already interconnected as of the effective date of the 2015 revisions to this Standard, unless the Interconnection Customer proposes a Material Modification, transfers ownership of the Generating Facility,, or application of the 2015 revisions to the Commission's interconnection standard are agreed to in writing by the Utility and the Interconnection Customer. This Standard shall apply if the Interconnection Customer has not actually interconnected the Generating Facility as of the effective date of the 2015 revisions.

Commented [A1]: This section will need to be updated for new revision

Any Interconnection Customer that has not executed an interconnection agreement with the Utility prior to the effective date of the 2015 revisions to this Standard shall have 30 Calendar Days following the later of the effective date of the Standards or the posted date of notice in writing from the Utility to demonstrate site control pursuant to Section 1.6, and to post the deposit outlined in Section 1.4.

Any Interconnection Customer that has executed an interconnection agreement with the Utility prior to the effective date of this Standard but the Utility has not actually interconnected the Generating Facility, shall have 60 Calendar Days to submit Upgrade and Interconnection Facility payments (or Financial Security acceptable to the Utility for Interconnection Facilities only) required pursuant to Section 5.2. Any amounts previously paid by the Interconnection Customer at the time deposit or payment is due under this Section shall be credited towards the deposit amount or other payment required under this Section.

1.1.4 Prior to submitting its Interconnection Request, the Interconnection Customer may ask the Utility's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Utility shall respond within 10 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. All Utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to Interconnection Agreement are to the North Carolina Interconnection Agreement. (See Attachment 9.)

**In-Service Date** – The date upon which the construction of the Utility's facilities is completed and the facilities are capable of being placed into service.

**Interconnection Customer** - Any valid legal entity, including the Utility, that proposes to interconnect its Generating Facility with the Utility's System.

**Interconnection Facilities** – Collectively, the Utility's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Generating Facility to the Utility's System. Interconnection Facilities are sole use facilities and shall not include Upgrades.

**Interconnection Facilities Delivery Date** – The Interconnection Facilities Delivery Date shall be the date upon which the Utility's Interconnection Facilities are first made operational for the purposes of receiving power from the Interconnection Customer.

**Interconnection Request** - The Interconnection Customer's request, in accordance with these procedures, to interconnect a new Generating Facility, or to change the capacity of, or make a Material Modification to, an existing Generating Facility that is interconnected with the Utility's System.

**Interdependent Customer (or Interdependent Project)** means an Interconnection Customer (or Project) whose Upgrade or Interconnection Facilities requirements are impacted by another Generating Facility, as determined by the Utility.

**Interim Interconnection Agreement** – The Interconnection Agreement that specifies the Preliminary Estimated Interconnection Facilities Charge, Preliminary Estimated Upgrade Charge, excludes Milestones, and must be cancelled and replaced with a Final Interconnection Agreement.

**Line Section** – A portion of a distribution circuit bounded by an automatic sectionalizing device and the end of the feeder. When applying this to the 15% of peak load screen described in Section 3.2.1.2 or the 100% of minimum load screen as described in Section 3.4.3.1, the smallest line section to be evaluated should begin at the first line recloser or circuit breaker upstream of the Point of Interconnection.

**Commented [A2]:** "or the 100% of minimum load screen as described in Section 3.4.3.1" is the one change from Exhibit SBA-Direct-2. This change is explained in the Rebuttal Testimony of IREC Witness Brian M. Lydic on page 19.

"**Material Modification**" means a modification to machine data or equipment configuration or to the interconnection site of the Generating Facility that has a material impact on the cost, timing or design of any Interconnection Facilities or Upgrades. Material Modifications include project revisions proposed at any time after receiving notification by the Utility of a complete Interconnection Request pursuant to Section 1.4.3 that 1) alters the size or output characteristics of the Generating Facility from its Utility-approved Interconnection Request submission; or 2) may adversely impact other Interdependent Interconnection Requests with higher Queue Numbers.

Indicia of a Material Modification, include, but are not limited to:

**Maximum ~~Physical Export Capability~~Generating Capacity Requested** - The term shall mean the maximum continuous electrical output of the Generating Facility at any time ~~at a power factor of approximately unity~~ as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period.

Commented [A3]: Power Factor requirements are clarified in Section 1.8 of the IA.

**Month** – The term "Month" means the period intervening between readings for the purpose of routine billing, such readings usually being taken once per month.

**Nameplate Capacity** – The term "Nameplate Capacity" shall mean the manufacturer's nameplate rated output capability of the generator. For multi-unit generator facilities, the "Nameplate Capacity" of the facility shall be the sum of the individual manufacturer's nameplate rated output capabilities of the generators.

**Net Capacity** – The term "Net Capacity" shall mean the Nameplate Capacity of the Customer's generating facilities, less the portion of that capacity needed to serve the Generating Facility's Auxiliary Load.

**Net Power** - The term "Net Power" shall mean the total amount of electric power produced by the Customer's Generating Facility less the portion of that power used to supply the Generating Facility's Auxiliary Load.

**Network Upgrades** - Additions, modifications, and upgrades to the Utility's Transmission System required to accommodate the interconnection of the Generating Facility to the Utility's System. Network Upgrades do not include Distribution Upgrades.

**North Carolina Interconnection Procedures** – The term "North Carolina Interconnection Procedures" shall refer to the North Carolina Interconnection Procedures, Forms, and Agreements for State-Jurisdictional Generator Interconnections as approved by the North Carolina Utilities Commission.

**Operating Requirements** - Any operating and technical requirements that may be applicable due to Regional Reliability Organization, Independent System Operator, control area, or the Utility's requirements, including those set forth in the Interconnection Agreement.

**Party or Parties** - The Utility, Interconnection Customer, and possibly the owner of an Affected System, or any combination of the above.

**Point of Interconnection** - The point where the Interconnection Facilities connect with the Utility's System.

**Preliminary Estimated Interconnection Facilities Charge** - The estimated charge for Interconnection Facilities that is developed using unit costs and is presented in the System Impact Study report and Interim Interconnection Agreement. This charge is not based on field visits and/or detailed engineering cost calculations.

Energy Source:

| Renewable | Non-Renewable |
|---|---|
| ❑ Solar – Photovoltaic | ❑ Fossil Fuel - Diesel |
| ❑ Solar – thermal | ❑ Fossil Fuel - Natural Gas (not waste) |
| ❑ Biomass – landfill gas | ❑ Fossil Fuel - Oil |
| ❑ Biomass – manure digester gas | ❑ Fossil Fuel – Coal |
| ❑ Biomass – directed biogas | ❑ Fossil Fuel – Other (specify below) |
| ❑ Biomass – solid waste | ❑ Other (specify below) |
| ❑ Biomass – sewage digester gas | |
| ❑ Biomass – wood | |
| ❑ Biomass – other (specify below) | |
| ❑ Hydro power – run of river | |
| ❑ Hydro power - storage | |
| ❑ Hydro power – tidal | |
| ❑ Hydro power – wave | |
| ❑ Wind | |
| ❑ Geothermal | |
| ❑ Other (specify below) | |

______________________________________________

______________________________________________

Type of Generator: Synchronous ____ Induction ____ Inverter ____

Total Generator Nameplate ~~Rating~~Capacity: __________ $kW_{AC}$ (Typical) __________ kVAR

Interconnection Customer or Customer-Site Load:__________ $kW_{AC}$ (if none, so state)

Interconnection Customer Generator Auxiliary Load: __________ $kW_{AC}$

Typical Reactive Load (if known): __________ kVAR

Maximum ~~Physical Export Capability~~Generating Capacity Requested: __________ $kW_{AC}$
(The maximum continuous electrical output of the Generating Facility at any time at a power factor of approximately unity as measured at the Point of Interconnection and the maximum kW delivered to the Utility during any metering period)

**Commented [A4]:** Proposed clean up change to bring language in line with glossary ("Nameplate Capacity" is defined as "the manufacturer's nameplate rated output capability of the generator. For multi-unit generator facilities, the "Nameplate Capacity" of the facility shall be the sum of the individual manufacturer's nameplate rated output capabilities of the generators."

List components of the Generating Facility equipment package that are currently certified:

| Number | Equipment Type | Certifying Entity |
|---|---|---|
| 1. ______ | ______________________ | ______________ |
| 2. ______ | ______________________ | ______________ |
| 3. ______ | ______________________ | ______________ |
| 4. ______ | ______________________ | ______________ |
| 5. ______ | ______________________ | ______________ |

I / A



~~DEG/DEP~~ Duke Progress
Auck Cross Exhibit No. 1

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I/A
vol. 5



# Exhibit PB-1

I/A

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Feb 13 2019

# PAUL BRUCKE, PE

109 E Poplar Ave • Carrboro, NC 27510
E-Mail: paul@bruckeengineering.com

## SUMMARY

Electrical Engineer with experience on over 30 GW of solar PV projects in development, construction or operation including interconnection support on over 20 GW of solar PV projects.

## EXPERIENCE

**Brucke Engineering :: Principal Engineer** **Feb 2016 – Present**

Carrboro, NC

Consulting with PV project developers, owners and utilities on interconnection, system design and engineering and plant operations.

**Cypress Creek Renewables :: VP of Engineering** **Dec 2014 – Feb 2016**

Cary, NC

Managed technical project development. Hired and managed engineering department. Provide interconnection support for projects in development and design engineering review of contractor's work and of projects being considered for acquisition.

**Black & Veatch :: Manager of Engineering, Renewable Energy** **Jan 2013 – Nov 2014**

Cary, NC

Managed Owner's Engineering and Independent Engineering services for solar PV projects in the US, Canada, Mexico, Central America and South America. Services included interconnection support, project site evaluation and feasibility studies, conceptual design, detailed design, design review, production estimation, construction monitoring, EPC bid review, EPC contract negotiation support and project technical review for investor due diligence.

**Strata Solar :: Director of Engineering** **Feb 2009 – Jan 2013**

Chapel Hill, NC

Grew Engineering Department from 1 engineer to a team of 13 engineers, architects, designers and field techs. Directed PV system design, construction monitoring, commissioning and O&M. Owner of Strata Engineering, PLLC, used for contracting engineering-only projects for other solar companies in NC. Responsible for preparing proposals, managing work and invoicing for these projects. Provided commercial sales support including feasibility analysis, economic analysis, preliminary engineering, meeting with customers, and generating full proposals.

**Qimonda (formerly Infineon Technologies) :: Staff Engineer** **Aug 1999 – Dec 2008**

Cary, NC / Munich, Germany

DC power system design for microelectronic components (DRAM) with a focus on generator efficiencies and consumption reduction. Mixed signal and high-speed logic design. Led, mentored and trained other engineers. Two-year delegation to Infineon HQ in Munich, Germany (2003-2005).

**Mitsubishi Semiconductor :: Engineer** **Jan 1998 – Aug 1999**

Durham, NC

Circuit layout and verification for microelectronic components (DRAM and hard disc drive ICs)

# EDUCATION

**Clemson University :: BSEE :: cum laude** **Dec 1997**

Clemson, SC

# SKILLS

PV PROJECT DEVELOPMENT: site selection, entitlements and approvals, interconnection application, preliminary engineering, energy and revenue estimation

PV PROJECT ENGINEERING: electrical design and layout, NEC compliance, system optimization, technology evaluation, equipment selection and BOMs, contractor submittal approval, construction monitoring and inspection, commissioning, utility interconnection

PV PROJECT O&M: monitoring system selection and integration, maintenance protocol development, troubleshooting equipment faults and performance issues

PROJECT MANAGEMENT: budgeting, scheduling, resource allocation

MANAGEMENT: leadership, building and motivating teams, training, mentoring

SOFTWARE: PVsyst, PVWATTS, SAM, AutoCAD, SketchUp, Microsoft Office, Microsoft Project

# LICENSE & CERTIFICATIONS

Professional Engineer (AL, CA, CO, FL, GA, KY, ME, MD, MI, MN, MS, NC, NY, OR, SC, TN, TX, VA, WA)
NABCEP Certified PV Installation Professional

# PUBLICATIONS

Reactive Power Control in Utility Scale PV, SolarPro magazine, June/July 2014
DC Arc Flash Risk Assessments for Photovoltaic Systems, IEEE PVSC Proceedings, June 2016

# AFFILIATIONS

IEEE – Senior Member
IEEE Power & Energy Society – member
IEEE 1547 Revision Working Group – member
North Carolina Sustainable Energy Association – member
Professional Engineers of NC - member

# Exhibit PB-2

DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

# PRE-READ PACKET

## FOR STAKEHOLDER WORKSHOP

11/08/18

NCSEA Exhibit PB-2



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# INTRODUCTION TO THIS PRE-READ DOCUMENT AND ROCKY MOUNTAIN INSTITUTE'S ROLE AS WORKSHOP FACILITATOR

DUKE ENERGY

## ABOUT THIS DOCUMENT

- This read-ahead packet includes information about the November 8 workshop, including:
  - Workshop objectives, agenda, and list of attendees.
  - Duke Energy's draft grid improvement portfolio and detailed information on how it was created.
- Please familiarize yourself with these materials so that you are prepared for the workshop and ready with any questions.

## ROCKY MOUNTAIN INSTITUTE'S ROLE

- Rocky Mountain Institute (RMI) has been contracted by Duke Energy to act as a neutral facilitator for the this workshop.
- RMI is an independent, nonprofit organization with 35 years of experience in analysis and partnerships around electricity grid investment and regulatory innovation across the United States and globally.
- RMI's role in this workshop includes:
  - Pre-event interviews with many stakeholders
  - Agenda design & facilitation of the workshop
  - Preparation of a post-event summary report

*We look forward to seeing you on November 8 !*

# WORKSHOP OBJECTIVES, AGENDA & PARTICIPANTS

DUKE ENERGY

*North Carolina University Club. 4200 Hillsborough Street, Raleigh, North Carolina 27606*

WORKSHOP OBJECTIVES:

- Obtain stakeholder input to Duke Energy's outlook on seven megatrends shaping grid improvement decisions.
- Describe and get feedback on how Duke Energy has used stakeholder input, the impact of megatrends on grid needs, and a prioritization methodology to develop a grid improvement portfolio.
- Describe the benefits and risks of the draft program portfolio, and hear from stakeholders what changes they propose and why.

| | |
|---|---|
| 8:30am | Sign In |
| 9am | PROMPT START and Welcome<br>Objectives, Agenda, Ground Rules<br>Introductions<br>Overview of Analysis<br>Megatrends |
| 11:40am | LUNCH |
| 12:25pm | Portfolio Prioritization Methodology<br>Input on Grid Modernization<br>Discussion and Next Steps<br>Check-Out |
| 4:00pm | ADJOURN |

Coffee, tea, lunch and afternoon snacks provided

PARTICIPATING ORGANIZATIONS INCLUDE:
- Advanced Energy
- Brooks Pierce Tech Customers
- Carolina Utility Customers Association
- Clean Air Carolina
- Clean Energy
- Corning Incorporated
- DOJ – Consumer Protection
- Environmental Defense Fund
- ElectriCities of North Carolina
- Energy NC
- Evergreen Packaging
- Nekins at Law
- NC Interfaith Power & Light
- NC Justice
- NC Sustainable Energy Association
- NC WARN
- NC Manufacturers Alliance
- NC State University (School of Public Affairs)
- Nicholas Institute for Environmental Policy Solutions
- North Carolina Department of Environmental Quality
- North Carolina League of Conservation Voters
- Nutrien
- Public Staff - NC Utilities Commission
- Sierra Club
- Southern Environmental Law Center
- US Marine Corp (Government and External Affairs)
- US Marine Corp (Regional Energy Programs)
- Varentec
- Vote Solar
- Warren Hicks, Bailey & Dixon, LLP

## THIS WORKSHOP IS PART OF A BROADER STAKEHOLDER ENGAGEMENT PROCESS AROUND DUKE ENERGY'S GRID IMPROVEMENT PLAN IN NORTH CAROLINA

DUKE ENERGY

May 2018 Workshop

November 2018 Workshop

Ongoing Stakeholder Engagement 2019 & Beyond

- Stakeholder perspectives are necessary to ensure Duke Energy is making the best decisions possible for North Carolina customers.
- In this workshop, Duke Energy wishes to inform stakeholders of the status of its revised draft Grid Improvement Plan and get critical feedback that could inform the final Grid Improvement Plan for North Carolina.
- Stakeholder input has already shaped the revised draft Grid Improvement Plan and will continue to do so.

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DUKE ENERGY

DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

# MEGATRENDS IMPACTING NORTH CAROLINA

## FOR STAKEHOLDER WORKSHOP

11/08/18

NCSEA Exhibit PB-2

# TRENDS IN OUR SERVICE TERRITORY

DUKE ENERGY



**In the context of the emerging distributed electric system, Duke Energy has recognized multiple trends and facts that warrant recognition and analysis.**

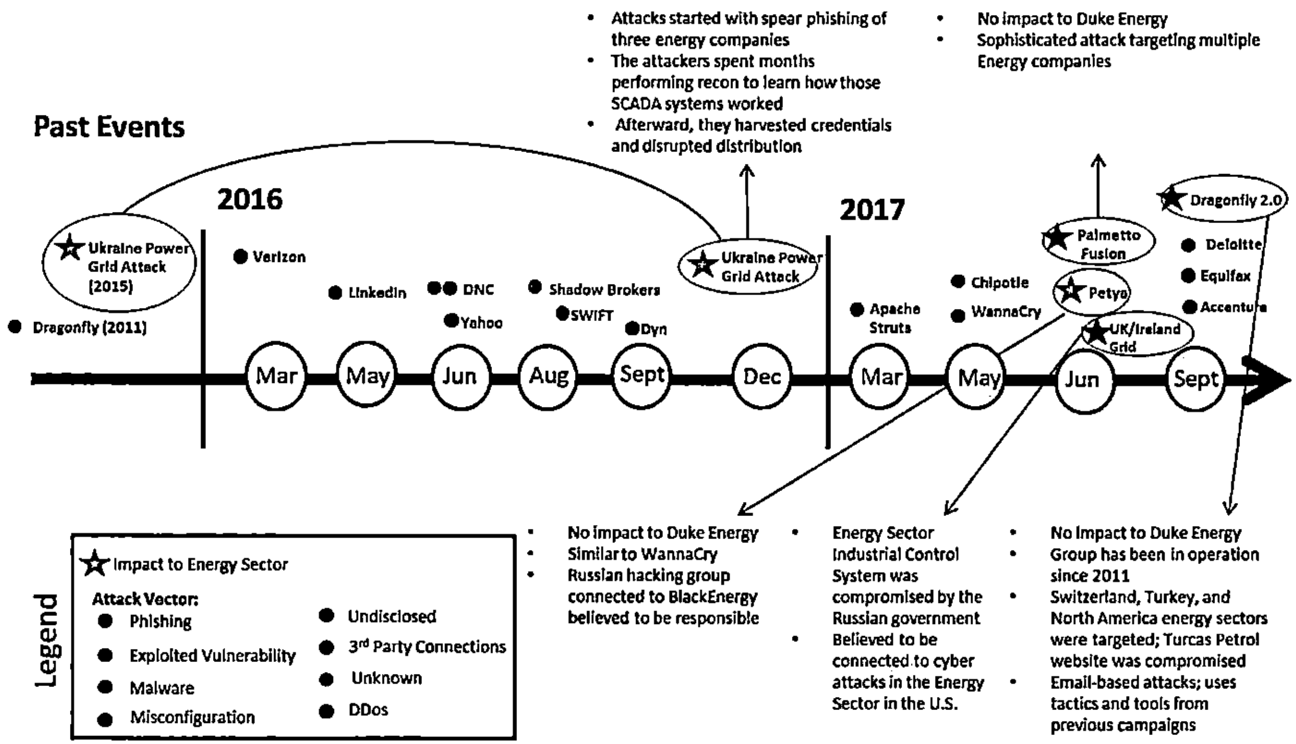
| | |
|---|---|
| I | Threats to grid infrastructure |
| II | Technology advancements – Renewables and DER |
| III | Lower carbon future and other environmental trends |
| IV | Impact of weather events |
| V | Grid improvement |
| VI | Concentrated population growth |
| VII | Customer expectations |

DUKE ENERGY



## What is happening?

- Purposeful threats, both physical and cyber, to the electric grid are on the rise worldwide




Source: Duke Energy[1]

# I. THREATS TO GRID INFRASTRUCTURE

DUKE ENERGY

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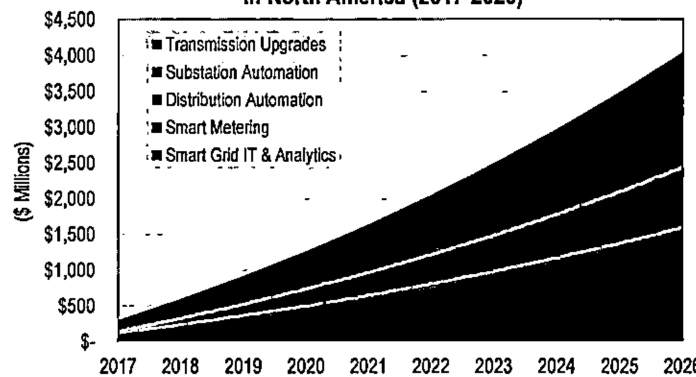
Feb 13 2019

## What is happening?

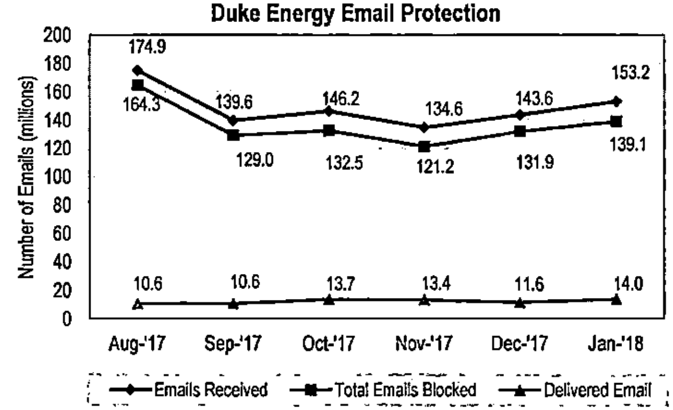
- Grid cybersecurity investment expected to grow from $300 million in 2017 to $4 billion by 2026[2]
- Increasing points of entry: as of November 2017, an estimated 378 million Internet of Things (IoT) devices were vulnerable to hacking[3]
- Ukrainian power grid attacks in 2015 and 2016 and more recent ransomware attacks driving utilities to expand beyond compliance-based management practices[4]
    - Industrial Control Systems Cyber Emergency Response Team estimates a similar incident in the US would result in damages totaling between $243 billion and $1 trillion[5]
- Cyber attacks impacting Southeast municipalities and utilities
    - Ransomware attacks in Mecklenburg County (Charlotte) and Atlanta impacted key government services including bill payments[6]
    - North Carolina fuel distribution company experienced $800,000 cyber heist[7]
    - Duke Energy protection solutions currently blocking +90% of incoming emails[8]

**Cumulative Smart Grid Cybersecurity Investment in North America (2017-2026)**




Source: Navigant Research Cybersecurity for the Digital Utility[9]

**Duke Energy Email Protection**




Source: Duke Energy[10]

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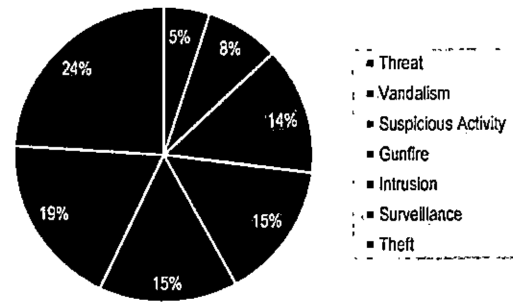
# I. THREATS TO GRID INFRASTRUCTURE

DUKE ENERGY

## What is happening?

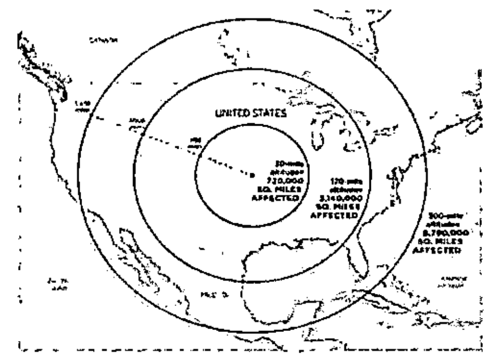
- Electricity Information Sharing and Analysis Center (E-ISAC) assesses that there will be an increase in theft, especially in areas more negatively impacted by socio-economic issues[11]
    - Theft was the top physical threat to the grid in 2017[12]
- The number of terrorist attacks is increasing
    - Physical/sniper attack on PG&E transmission station damaged 17 substation transformers, caused $15 million in damages, and led to $100 million in physical security investments[13]
- Electromagnetic Pulse (EMP) generated at an altitude of 30 miles above the earth can severely damage electronics within an area of about 720,000 square miles[14]
    - Currently there is limited protective equipment installed to address consequences of EMP-like events[15]
    - Have potential to cause wide-scale long-term losses with economic costs[16]
    - Cost of damage from the most extreme solar event is estimated to cost $1 trillion-$2 trillion with recovery time of 4-10 years[17]

**Breakdown of Physical Security Incidents for 2017**




Source: NERC[18]

**Potential Magnitude of EMP Events**




Source: The Heritage Foundation[19]

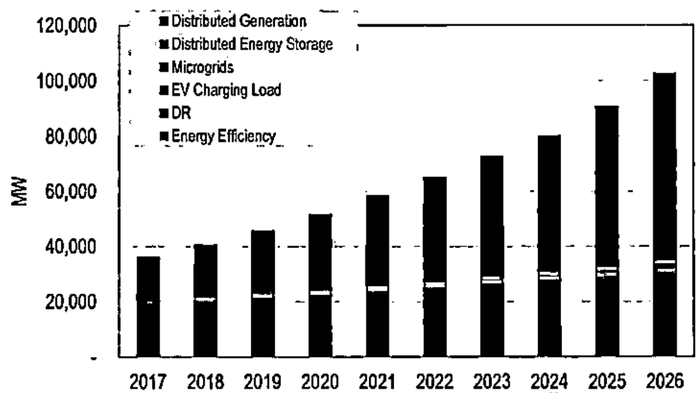
# II. TECHNOLOGY ADVANCEMENTS – RENEWABLES AND DER

DUKE ENERGY

## What is happening?

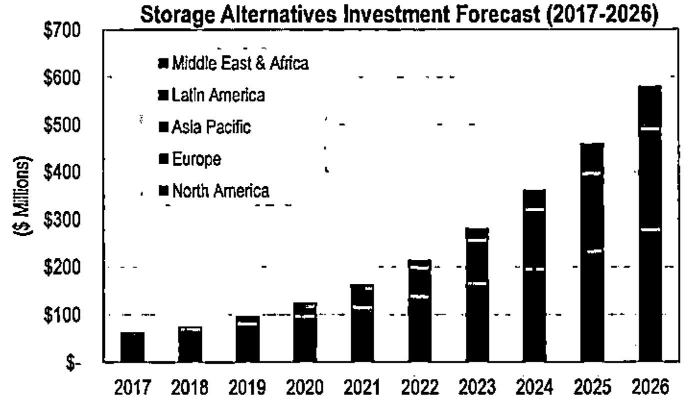
- Distributed energy resources (DER) expected to grow eight times faster than net new centralized generation in the next 10 years globally[20]
    - Distributed generation, including solar PV, remains a dominant contributor to this forecast
    - EVs and EV charging are the fastest growing segments
- Spending on energy storage solutions and alternatives is forecasted to increase at an annual rate of 18% over the next 10 years in North America[21]
- Renewables and DER becoming significant capacity resource for Duke Energy in North Carolina
    - Recent North Carolina Integrated Resource Plan (IRP) includes capacity from renewable resources, energy efficiency, and demand-side management, increasing from 8% in 2019 to 16% in 2033 (Duke Energy Carolinas (DEC)) and 18% in 2019 to 22% in 2033 (Duke Energy Progress (DEP))[22]
    - Duke Energy customer-sited solar programs totalling 10 MW in DEC and DEP approved in May 2018[23]
        - The customer-scale solar programs for both residential and commercial customers in both DEC and DEP reached the 10 MW cap for 2018 within three weeks[24]
    - The Duke Energy North Carolina interconnection queue for DEC and DEP combined represents approximately 12 GW[25]

Global DER Capacity Forecast (2017-2026)




Source: Navigant Research Global DER Deployment Forecast Database[26]

Storage Alternatives Investment Forecast (2017-2026)




Source: Navigant Research[27]

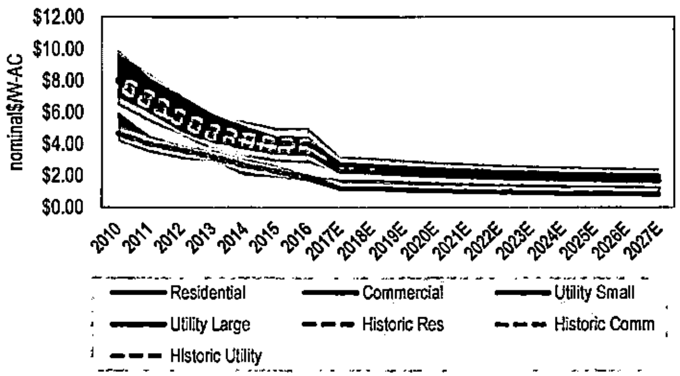
# II. TECHNOLOGY ADVANCEMENTS – SOLAR PV

DUKE ENERGY

## What is happening?

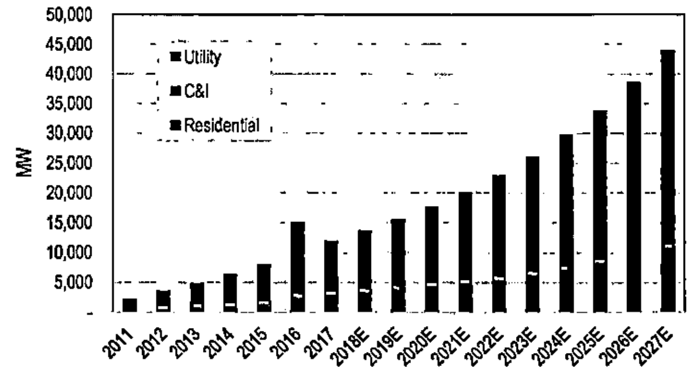
- Solar PV is becoming increasingly competitive[28]
  - Cost of utility-scale solar has dropped 66% since 2010 and is projected to decline by 3.6% per year in the next 10 years[29]
  - Cost of distributed solar has dropped 67% since 2010 and is projected to decline by 3.1% per year in the next 10 years[30]
- Solar PV efficiency has increased which lowers overall installed cost by minimizing the number of panels needed to achieve the same output
- Module efficiency has increased 2% annually since 2007[31]
  - Manufacturing is shifting to higher efficiency monocrystalline panels
- Distributed solar PV installations are projected to continue increasing in North Carolina
  - North Carolina ranked 2nd in the nation for the highest solar generation capacity[32]
  - Over 4,400 MW of solar currently installed in North Carolina[33]
  - Installed capacity in North Carolina is projected to increase 7% per year 2017-2026[34]

Solar PV Cost Declines (2010-2027)




Source: Navigant, NREL[35]

Historical and Forecasted Annual Solar PV Installed Capacity in US (2011-2027)




Source: Navigant Research Market Data: Global Distributed Solar PV[36]

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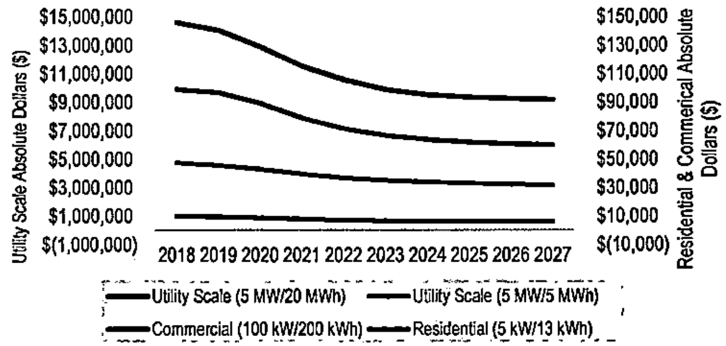
# II. TECHNOLOGY ADVANCEMENTS – BATTERY STORAGE

DUKE ENERGY

## What is happening?

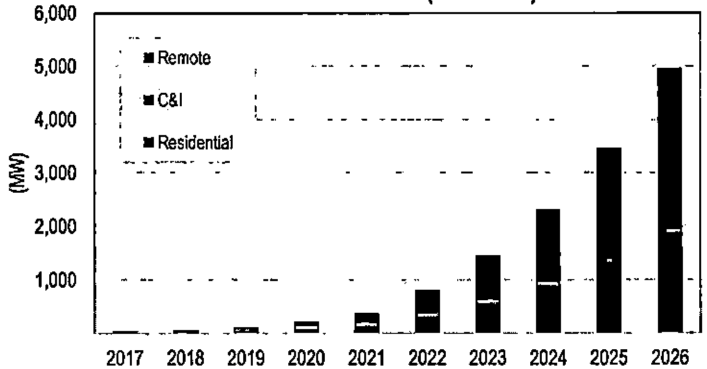
- Battery storage costs expected to decline over the next 10 years in the US
  - Cost of utility-scale storage is projected to decline by 5.4% per year, and utility investment in storage is likely to increase to provide more grid flexibility[37]
  - Cost of distributed storage projected to decline by 5% per year[38]
- Storage installations are projected to increase 2018-2027 in North America:
  - 35% per year for utility-scale[39]
  - 25% per year for distributed storage[40]
- Storage is increasingly installed co-located with renewable energy. Installed capacity of solar plus storage is projected to increase in North America:
  - 57% per year 2018-2026 for utility-scale[41]
  - 76% per year for distributed storage[42]
- Duke Energy's 15-year forecast includes 300 MW of battery energy for the Carolinas storage to improve reliability and grid support[43]

**Li-Ion Battery Storage System Capital Cost Forecast (2018-2027)**




Source: Navigant Research Large Commercial and Industrial Energy Storage [44]

**Annual Solar PV + Storage Power Capacity and Revenue in North America (2017-2026)**




Note: Remote, off-grid solar plus storage typically serves loads of 5 kW or less in remote areas without grid access

Source: Navigant Research Distributed Solar PV plus Energy Storage Systems[45]

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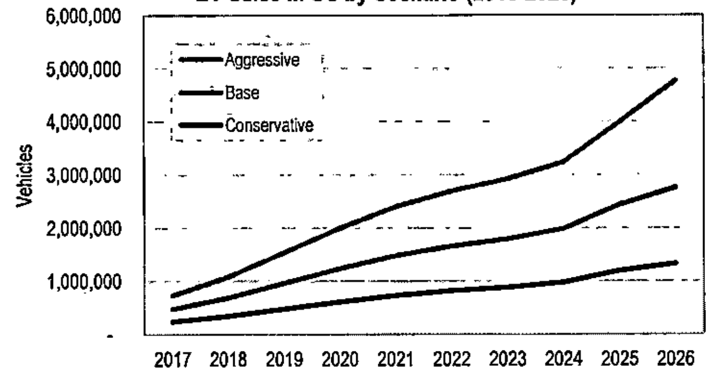
## What is happening?

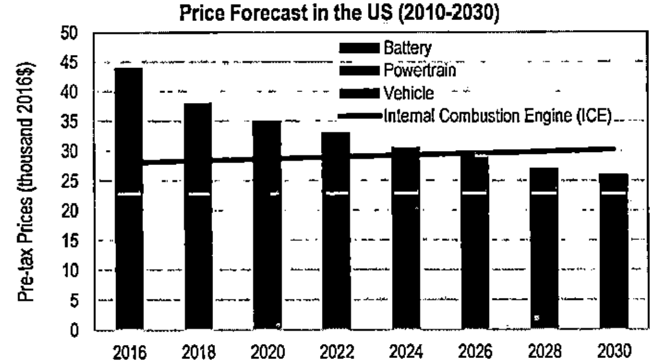
- Cost of EVs has decreased by 80% since 2010[46]
- EVs expected to be competitive with internal combustion engine (ICE) vehicles by 2030[47]
- General Motors announced all-electric, zero emissions future with 20 fully electric models by 2023[48]
    - "General Motors believes electric, self-driving, connected vehicles and shared mobility services will transform how we get around, and we are drawing the blueprint to advance our vision of a world of zero crashes, zero emissions, and zero congestion." – General Motors
- EV adoption is projected to increase
    - By 2027, there will be near 58M PEVs[49]
    - By end of 2018, over 5M PEVs will be on roads globally[50]
    - The number of US residential charging locations is estimated to reach ~6 million by 2025[51]
    - The global market of EVs should see continued sales growth at around 38% through 2020[52]
- EVs in North Carolina are projected to increase 42% annually[53]
    - ~8,500 PEVs are on North Carolina's roads today[54]
    - North Carolina Energy Policy Council recognizes that "the greatest impact of increased EV adoption will be on the distribution system, so whether there is high or low penetration, a modern grid will be required to support it."[55]

**EV Sales in US by Scenario (2016-2025)**




Source: Navigant Research EV Geographic Forecasts[56]

**Battery Electric Vehicle (BEV) and Internal Combustion Engine (ICE) Price Forecast in the US (2010-2030)**




Note: Vehicle prices based on medium segment price
Source: Bloomberg New Energy Finance[57]

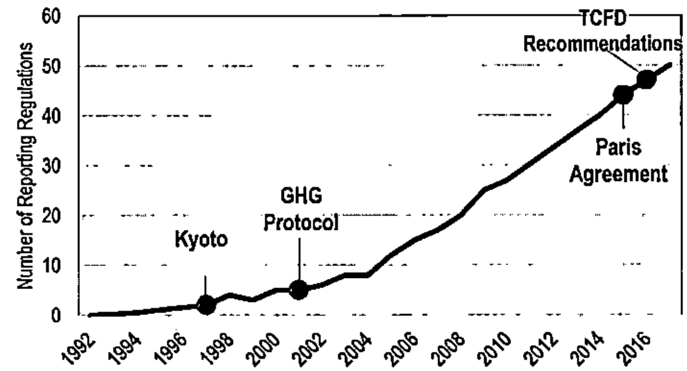
## III. LOWER CARBON FUTURE AND OTHER ENVIRONMENTAL TRENDS

DUKE ENERGY

### What is happening?

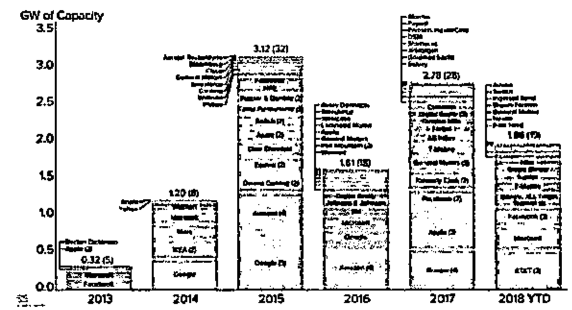
- Broad international commitment and pressure to reduce carbon emissions
- Cyclical federal environmental policy commitments (COP 21, CPP) but implementation of federal energy efficiency standards (transportation, lighting, etc.) underway
- Corporations making commitments and demanding renewable options
    - ~48% of Fortune 500 companies have sustainability and renewable energy commitments[58]
    - Leading NC corporations have set sustainability goals, including Bank of America, Lowe's, Owens Corning, Reynolds American, VF Corporation, Walmart, and Wells Fargo
    - 488 companies taking science-based climate action and 133 have approved targets[59]
    - 75 companies have committed to Corporate Renewable Energy Buyers' Principles with goal to "work with utilities and regulators to expand choices for buying renewable energy"[60]
- States and cities setting goals for renewables, low carbon transportation, and energy efficiency
    - Fifty percent of states are currently examining one or more of the following topics: (1) smart grid and advanced metering infrastructure (Smart Meters), (2) utility business model reform, (3) regulatory reform, (4) utility rate reform, (5) energy storage, (6) microgrids, and (7) demand response[61]
    - Electric utilities in North Carolina established a 40% carbon reduction goal from 2005 levels by 2030 with approximately 60% of electricity coming from carbon-free energy sources[62]
    - NC set renewable energy and energy efficiency portfolio standard (REPS) of 12.5% of 2021 sales[63]
    - Smart city initiatives being carried out in many NC cities, such as Charlotte and Cary
        - Envision Charlotte and Town of Cary Simulated Smart City projects are integrating energy efficient practices[64]

**Growth in Reporting Related to Greenhouse Gas Emissions (1992-2017)**




Source: World Business Council for Sustainable Development[65]

**Contracted Capacity of Corporate Power Purchase Agreements, Green Tariffs, and Outright Project Ownership**




Source: Business Renewables Center[66]

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# IV. IMPACT OF WEATHER EVENTS

DUKE ENERGY

## What is happening?

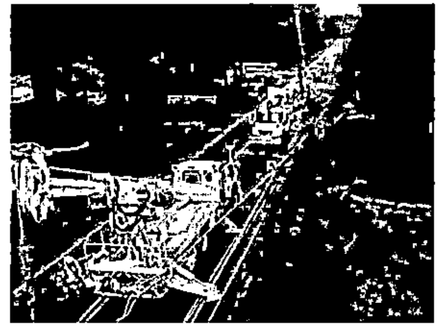
- North Carolina has faced major weather events, with Hurricanes Matthew (2016) and Florence (2018), and most recently Michael (2018) illustrating the magnitude of the challenge the grid faces today from weather
    - Approximately 715,000 outages in North Carolina during Hurricane Matthew[67]
    - Approximately 1.8 million total Duke Energy customer outages restored across the Carolinas during Hurricane Florence, ~1.6 million of which were Duke Energy customers in North Carolina[68]
        - ~ 45 transmission lines out, 185 miles of distribution lines down, and 10 substations flooded at peak of storm[69]
    - Approximately 1 million total Duke Energy customer outages restored across the Carolinas during Hurricane Michael[70]
- "I know North Carolina can rebuild, we have to rebuild in a smart way. We have to understand when you have two so called 500 year floods within 22 months of each other, not sure you're talking about a 500 year flood anymore. We've got something else on our hands."

  - NC Governor Roy Cooper[71]

**Hurricane Michael Impacts (2018)**

Source: Citizen Times[72]

**Hurricane Florence Impacts (2018)**



Source: T&D World[73]

**Hurricane Matthew Impacts (2016)**

Source: Chicago Tribune[74]

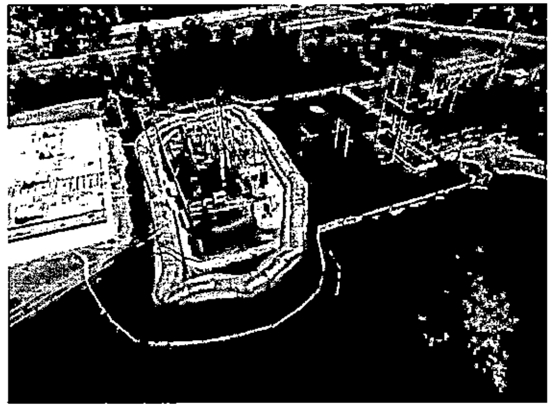
# IV. IMPACT OF WEATHER EVENTS

DUKE ENERGY

## What is happening?

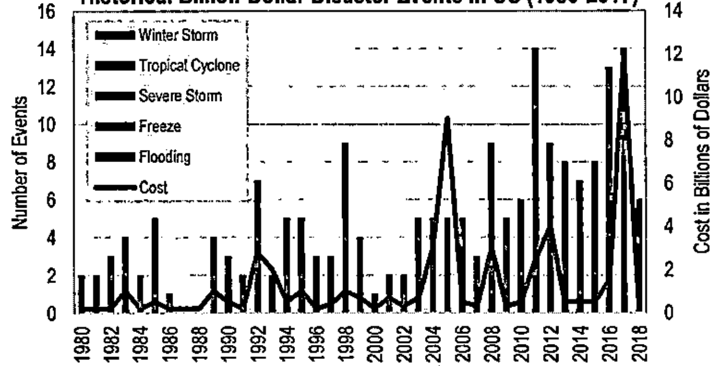
- North Carolina experienced over 300 bulk electric system outages related to weather events (2009-2017) and is part of a larger region that sees the most major storms[75]
- The number of customers impacted by weather events is increasing due to population growth in regions most affected by weather
- The average outage duration for each Duke customer served (SAIDI) in North Carolina increased by 20% (2012-2017)[76]
- Number of major event days (MEDs) have increased by 2% per year over the past 25 years[77]
- Number of Duke Energy NC customer outage events increased by 18% since 2012[78]

**Temporary Flood Mitigation at 6 Carolinas East Station**



Source: Duke Energy[79]

**Historical Billion-Dollar Disaster Events in US (1980-2017)**




Note: Costs are adjusted for Consumer Price index (inflation)

Source: NOAA[80]

# V. GRID IMPROVEMENT – NATIONAL VIEWS



## What is happening?

- Grid improvement technology has advanced over the last decade, and has given utilities alternatives to traditional grid infrastructure options.
  - Grid improvement got a boost from $4 billion in Smart Grid Investment Grants under the American Recovery and Reinvestment Act of 2009 (the Stimulus Act) which, combined with industry spending, led to nearly $8 billion in related projects[81]
  - "Smart" grids are expected to increase the grids' efficiencies by 9% by 2030. This is equivalent to saving more than 400 billion kilowatt-hours each year[82]
  - Grid improvement deployments reduce peak demands by 13% to 24%[83]
  - Savings between $46 billion and $117 billion are expected over the next 20 years[84]
  - Smart meters are expected to save more than $150 billion/year by 2020 by reducing the cost of power interruptions by more than 75%[85]
- The global market for smart grid IT and analytics for software and services is expected to grow from approximately $12.8 billion in 2017 to more than $21.4 billion in 2026[86]

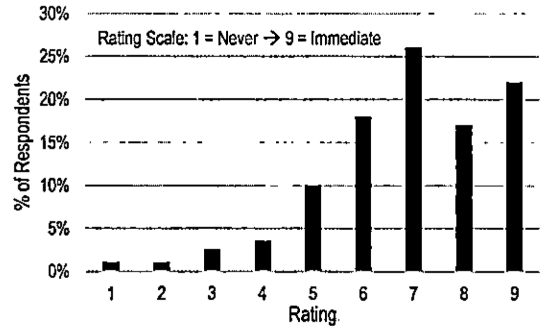
**Rapidly Advancing Smart Grid Technologies**

| Intelligent Devices | Information Technology |
|---|---|
| • High speed communication networks (fixed and wireless)<br>• Smart Meters<br>• Distribution Automation including intelligent switches, capacitors, and remote fault identification | • Advanced Distribution Management Systems (ADMSs)<br>• Integrated Volt/Volt-ampere reactive Control (IVVC)<br>• Fault, location, isolation, and service restoration (FLISR)<br>• Asset Management Systems (AMSs)<br>• Customer Information Systems (CISs)<br>• Demand Response Management Systems (DRMSs)<br>• Distributed Energy Resources Management Systems (DERMSs)<br>• Energy Management Systems (EMSs)<br>• Geographic Information Systems (GISs)<br>• Meter Data Management Systems (MDMSs)<br>• Advanced Analytics (Asset, Grid Operation, Demand-side, Customer) |

Source: Navigant[87]

**"Pulse of Power" Survey of Readers**

**How soon should the power industry adapt to a clean, intelligent, mobile, and distributed grid?**




Source: Public Utilities Fortnightly[88]

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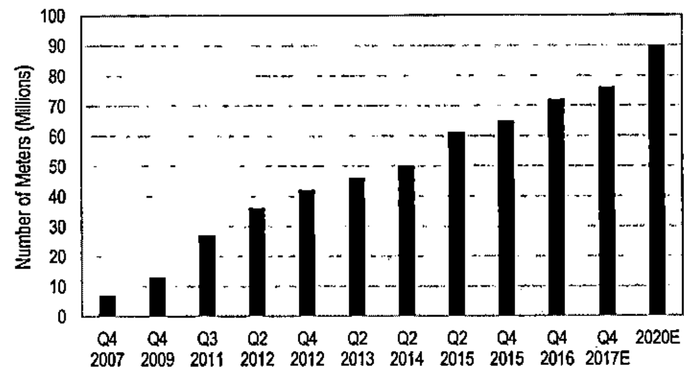
## What is happening?

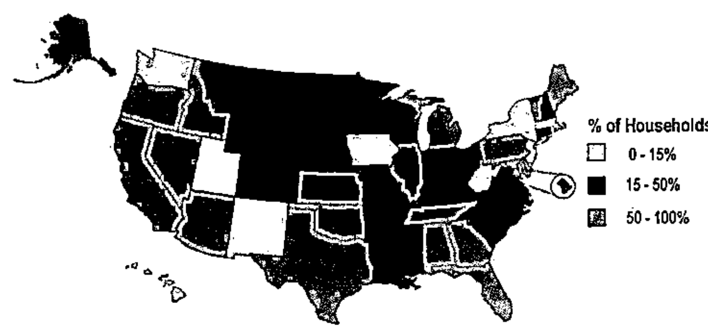
- Deployment of Smart Meters is an indicator of grid modernization adoption by utilities
    - Two-way Smart Meters allow utilities and customers to interact to support smart consumption applications using real-time or near real-time electricity data
    - Smart Meters support demand response and distributed generation, improve reliability, and provide information that consumers use to save money by managing their use of electricity
    - Smart Meter data provides utilities with detailed outage information in the event of a storm or other system disruption, helping utilities restore service to customers more quickly and reducing the overall length of electric system outages
- National Smart Meter installations are approaching 76 million and is projected to reach 90 million by 2020[89]
    - Currently, ~2 million North Carolina Duke Energy customers have Smart Meters installed (~1.8 million in DEC and ~0.16 million in DEP)[90]

**US Smart Meter Installations (2007-2020)**




Source: The Edison Foundation[91]

**Residential Smart Meter Adoption Rates by State (2016)**




Source: The Edison Foundation[92]

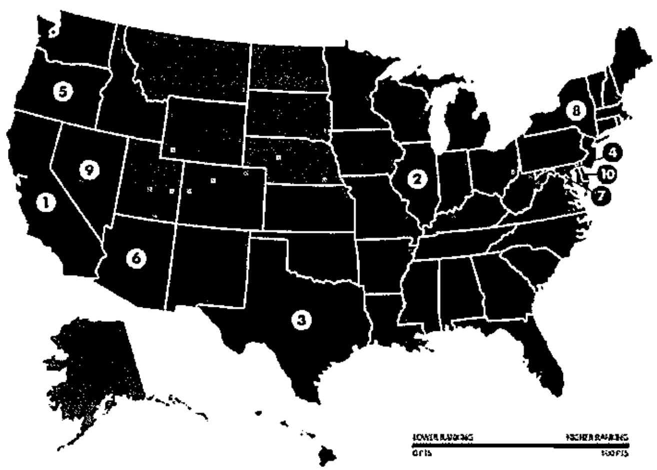
# V. GRID IMPROVEMENT – REGULATORY STATE POLICY ACTIONS

DUKE ENERGY

## What is happening?

- NC Energy Policy Council states that "utility grid modernization is a solution to address the increased complexity and demands from operating a changing electric grid. Due to the transient nature and potential imbalances of intermittent distributed renewable generation, modernizing the grid can address these issues more effectively than legacy devices in substations and distribution feeders today"[93]
- In Q1 2018, 37 US states and the District of Columbia took grid modernization actions involving regulations and legislature. Most of these actions involved Smart Meters, energy storage, and utility business model reforms[94]
- North Carolina was ranked 15th in the nation on the GridWise Alliance's 2017 Grid Modernization Index, which evaluates the leading states using a three-part score based on state support, customer engagement, and grid operations[95]

**Grid Modernization Index Across the US**



Source: GridWise Alliance[96]

**Sample of Targeted Cost Recovery Mechanisms for Grid Modernization Investment**

| State | Type of Investment |
|---|---|
| California | Research and technology development |
| Massachusetts | Grid modernization |
| Minnesota | Grid modernization |
| New Jersey | Hardening infrastructure modernization |
| Ohio | Grid modernization |
| Pennsylvania | Advanced metering |

Source: Navigant[97]

## V. GRID IMPROVEMENT – UTILITY BENCHMARKING

DUKE ENERGY

### What is happening?

- Utilities are adopting grid technology to support increasing DER penetration
- There are varying types of grid modernization technology, many of which are listed in the table below

**Benchmarking of Utility Grid Modernization**

| Smart Grid Investment | Utility 1 | Utility 2 | Utility 3 | Utility 4 | Utility 5 | Utility 6 | Utility 7 |
|---|---|---|---|---|---|---|---|
| DER Penetration* | 5% | 25% | 32% | 55% | 4% | <1% | <1% |
| Smart Meters | | ● | ○ | N/A** | ○ | ● | ● |
| Demand Response | ○ | ● | ● | ◐ | ◐ | | ◐ |
| Distribution Automation | ● | ◐ | ○ | ● | | ● | ● |
| Substation Automation | ◐ | ◐ | ○ | ◐ | ◐ | ● | ● |
| Advanced Communications | ● | ◐ | ◐ | ◐ | ◐ | ● | ○ |
| Energy Storage | ○ | ◐ | ◐ | ◐ | ○ | | ◐ |
| Electric Vehicle Charging | ◐ | ◐ | ○ | ◐ | ○ | ○ | ◐ |
| Volt VAR Optimization | ○ | ○ | ○ | | ○ | ◐ | ◐ |
| Time-of-use Pricing | | ◐ | ○ | N/A** | ◐ | | ● |
| DERMS/ADMS | ○ | ○ | ○ | ○ | ○ | ○ | ○ |
| Microgrids | | | ◐ | ○ | | | ◐ |
| Undergrounding of Circuits | ◐ | | ◐ | ● | | | ◐ |
| Recovery Mechanism | ● | ● | ● | ◐ | ● | ● | ● |

● **Large Scale:** utility has deployed technology in majority of its jurisdiction, and has begun evaluating the impacts on its system.

◐ **Pilot/Small Scale:** utility has deployed technology in one to a few locations, and has not been implemented long enough to evaluate its impact.

○ **Planned:** utility has not deployed the technology yet, but has plans for implementation in their most recent smart grid filing.

Source: Navigant[98]

*As percentage of peak demand. Note that utilities may define DER resources somewhat differently.
**Utility 4 market structure does not allow them to deploy Smart Meters or TOU rates

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# VI. CONCENTRATED POPULATION GROWTH

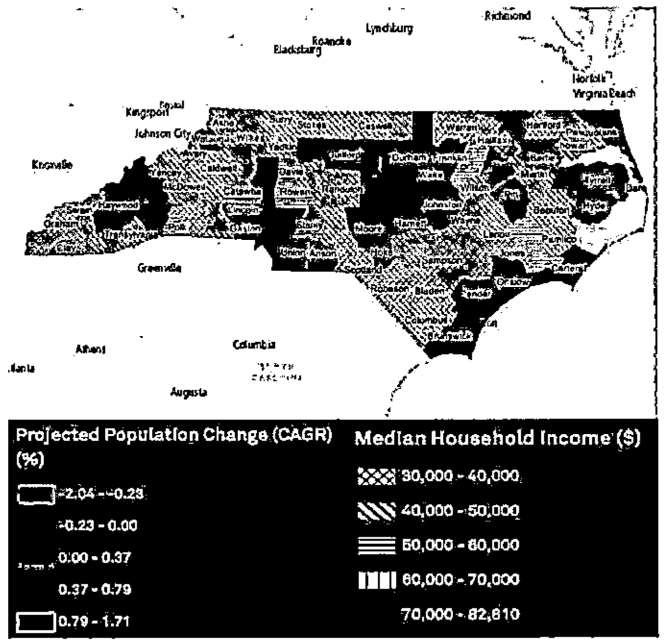
DUKE ENERGY



## What is happening?

- People, wealth, and jobs continue to concentrate in urban and suburban areas
  - Movement is being driven by shifting demographics and changing lifestyle preferences
  - Many suburban areas getting an urban makeover with mixed-use development, thoughtful public spaces, transit options, and community-focused street-level development
  - Businesses, industry, and construction are following suit to take advantage of increased population density and connectivity
- North Carolina's population is expected to grow by ~6% (2017-2026)[99]
  - Wake and Mecklenburg counties experienced high population growth of 19% and 17%, respectively (2010-2017)[100]
    - These two counties expect ~24% population growth through 2028[101]
  - Charlotte and Raleigh, the largest cities in North Carolina, accounted ~67% of NC's growth since 2010[102]
  - Even outside of economic development efforts so prevalent in North Carolina, a significant number of rural counties project stagnant or declining population
- Load is growing with population requiring new infrastructure
  - Load in Raleigh and Charlotte growing 3% and 6% per year, respectively[103]
  - There are challenges and costs siting new infrastructure in constrained areas

**NC Projected Population and Income Demographics**




Source: S&P Global[104]

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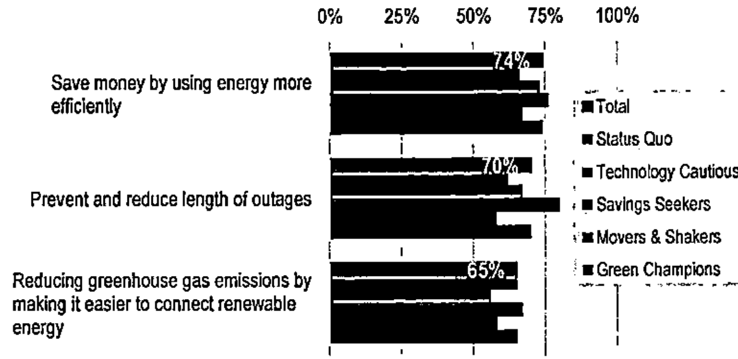
# VII. CUSTOMER EXPECTATIONS

DUKE ENERGY

## What is happening?

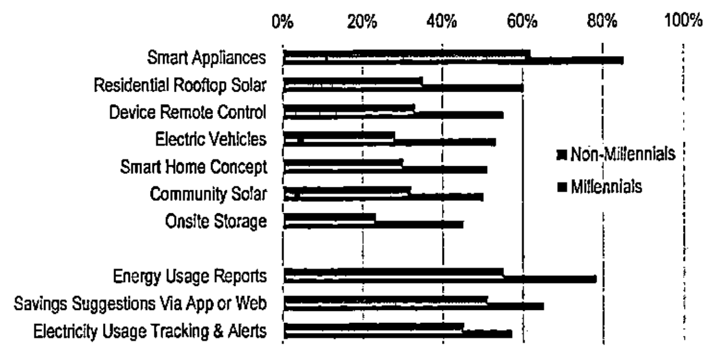
- Customers want to save money and reasonably reduce outages and greenhouse gas emissions[105]
  - Relative importance of these three may vary across customer personas, but they remain consistently the top factors
  - Customers want smart grid investments to reflect these needs
- To address these needs, customers are interested in new technology and increased control over their usage, including (1) smart appliances, (2) rooftop solar, and (3) device remote control[106]
- Millennials are far more interested in energy-related topics than non-millennials[107]
- Duke Energy's high growth business segments (advanced manufacturing, biotechnology, data centers, healthcare) requiring substantial mission-critical electrical infrastructure and cost-effective energy management services
- NC Energy Policy Council recognizes that "as the electric grid in North Carolina ages, it must keep pace with emerging technologies and customer expectations"[108]

**Factors customer perceive as important for utility supply**




Note: These are the top 3 choices for all types of respondents
Source: Smart Energy Consumer Collaborative[110]

**Interest in Energy-related Concepts**




Source: Smart Energy Consumer Collaborative[111]

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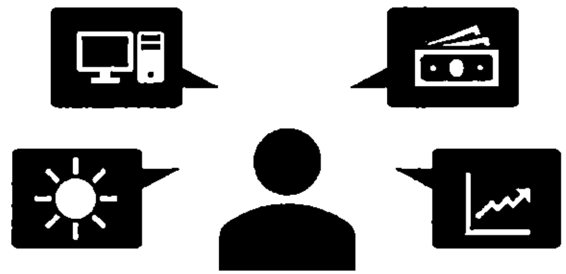
# VII. CUSTOMER EXPECTATIONS

## What is happening?

**Today, in North Carolina:**[112]



- Customers want their power to be on all the time as much as this is reasonably possible
- Customers want their power to be safe
- Customers do not want their power company to harm the environment
- Customers want their power to be as cheap as reasonably possible
- Customers want their interactions with the power company to be as easy and user-friendly as possible
- Customers want increases to their power bills to be minimal, infrequent, and predictable as possible
- Customers want to be informed of problems and issues in advance where possible and want to be updated with status reports as problems are being resolved
- Customers know and accept that there are things beyond our control that will cause power outages no matter what actions we take to prevent them
- Customers are more accepting of power outages when they know what caused the outage and how long it will take to restore power
- The frequency of outages and power quality issues are generally more important to customers than the duration of outages and events
- Most non-residential customers have built the effects of outages and power quality issues in to their business costs and are not willing to pay significantly more to prevent them
- Only some highly power-dependent customers (mostly complex businesses) have taken or are willing to take extraordinary measures to ensure a virtually uninterrupted supply of power

DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

# IMPLICATIONS

## FOR STAKEHOLDER WORKSHOP

11/08/18

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# IMPLICATIONS TO OUR CUSTOMERS FROM THE MEGATRENDS

DUKE ENERGY



**Our customers are impacted by the megatrends, and, under business as usual (BAU), our customers' expectations will not be met and we will miss the opportunity to optimally use advanced technology.**

| | |
|---|---|
| I | Increased costs |
| II | Reduced reliability and resiliency |
| III | Reduced ability to manage and integrate distributed energy resources (DER) |
| IV | Reduced ability to meet customer expectations and commitments |
| V | Reduced economic competitiveness for North Carolina |
| VI | Increased geographic and demographic disparity |

# I. INCREASED COSTS

DUKE ENERGY

## Under business as usual, costs to customers may increase as compared to emerging alternatives.

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | Costs to build BAU infrastructure in urban and suburban areas with concentrated growth are increasing, and do not provide enhanced capabilities to meet expected future grid needs. These costs will be borne by all customers, including those in rural areas that are unaffected. | Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus lower costs for all customers from what they would otherwise be. Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively. |
| Technology Advancements – Renewables and DER | Because DER is becoming more cost competitive, customers are installing DER and EVs, which, in turn, require improvements to the grid beyond BAU which increases costs if not done in a proactive and planned manner. The reduced load from DER can also lead to higher bills. | Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid. |
| Grid Modernization | "Like for like" replacement of technology will not lower costs beyond what it is today because capital and operating cost will be unchanged. Further, as the grid is impacted by other trends, existing grid technology may require more rapid replacement, thus increasing costs. | Using advanced grid technologies, system and operational efficiency are increased which lower costs to customers from what they would otherwise be. |
| Customer Expectations | Customers want to save money and under business as usual, costs will not decline and may go up. As the grid increasingly interconnects DER, interconnection costs of an individual project increase, making it cost prohibitive for customers to have more DER options. | With appropriate grid capabilities, such as ability to manage two-way power flow and intermittent resources, customers will have options that help them manage their costs better, including DER and usage management tools. |
| Environmental Commitments | Corporations and governments will not be able to meet their environmental goals and commitments if it becomes cost prohibitive to do so. And, in the case where interconnection costs are not incurred, such as with EV, costs to meet these goals and commitments are borne by all customers. | Advanced tools and technologies will enable greater application of DER on the grid, including renewable energy resources. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid. |
| Impact of Weather Events | Absent resiliency and reliability improvements, customers will see increased costs from outages as they increase in number and severity. These costs include those incurred by the utility and by customers. | Proactively hardening the system and building advanced monitoring, smart control and grid intelligence can reduce the occurrence and duration of outages, saving customers money compared to business as usual. |
| Threats to Grid Infrastructure | Absent adequate protection against modern threats, costs to customers will increase due to increased attacks. These costs include those incurred by the utility and by customers. | By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, occurrence and duration of outages can be reduced saving customers money compared to business as usual. |

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some issues = Many issues

# II. REDUCED RELIABILITY AND RESILIENCY

DUKE ENERGY



## Under business as usual, reliability will not improve and may decrease.

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | In concentrated growth areas, reliability will decrease if improvements to the grid don't keep pace with concentrated load increases and DER penetration. Reliability will decrease in rural areas where flat load growth does not support traditional grid strategies. | Advanced system controls, intelligence, planning, and automation can improve overall system efficiency using existing and new assets and thus can improve reliability for all customers. .Additionally, grid capacity needs and the need for two-way power flow can be addressed proactively, which can improve reliability. |
| Technology Advancements – Renewables and DER | Because DER is becoming more cost competitive, customers are installing DER and EV at an increasing rate, which may decrease reliability due to voltage fluctuation and capacity limitations on the distribution system. | Using rapidly advancing technology and systems, the utility can provide active monitoring and control power flow and improved voltage fluctuation issues using "grid-edge" decision making. Non-traditional applications are also an opportunity to improve reliability. |
| Grid Modernization | "Like for like" replacement of existing grid infrastructure will not improve reliability beyond what it is today because functionality will not have improved. In particular, the number of customers that experience multiple interruption per year will increase (CEMI-6). | Rapidly advancing grid technologies are available to improve grid reliability, including improving visibility to a more granular level of where outages are occurring and enable grid-edge decision making and control. |
| Customer Expectations | Customer satisfaction will decrease with increased outages, and reduced power quality, as customers are inconvenienced or unable to work. These outages may be caused from voltage or power flow issues from DER, traditional infrastructure, or major events such as weather or cyber attack | Customers expectations of reduced outages (either short- or long-term) and better power quality would be addressed with the use of rapidly advancing grid technology and systems. |
| Environmental Commitments | Customers with environmental commitments will interconnect DER which could cause voltage and power flow issues on the grid resulting in reduced reliability. Conversely, if DER is curtailed to address the reliability issues, customers will be prevented from meeting their commitments. | Using advanced grid technologies and systems helps customers meet their environmental commitments without sacrificing reliability or resiliency. |
| Impact of Weather Events | The BAU approach of reacting to damage when storms occur will not improve resiliency. In particular, in concentrated areas, when storms damage equipment, it affects more customers. | Using advanced grid technologies and systems will reduce frequency of short-term outages and reduce time to recover from major storm-induced outages. Undergrounding or hardening the most outage prone lines reduces costs and major event duration for all customers from what they would otherwise be. |
| Threats to Grid Infrastructure | Cyber and physical threats to grid infrastructure are increasing rapidly. Failure to keep pace with these threats will result in compromised reliability and resiliency of the electric grid. | Aggressive development and implementation of advanced system protections and protocols will help the electric grid remain protected from the ever increasing number and variety of threats it faces every day. Also, in the event that a threat is successful, these measures will help minimize damage/disruption that could impact customers. |

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some issues = Many issues

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# III. REDUCED ABILITY TO MANAGE AND INTEGRATE DER

DUKE ENERGY



**Business as usual limits the ability to manage and integrate DER, resulting in the need to curtail or issue moratoriums on customer-owned interconnection.**

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | The existing constrained grid in urban areas limits the ability to interconnect DER for customers who are interested in renewable energy, storage and electric vehicles. | Advanced tools and technologies that enable two-way power flows will allow for increased application of DER on the grid. Effectively planning for and optimizing the installation of DER's on the grid will lower costs for all customers beyond what they would otherwise be while maintaining safe and reliable operation of the grid. |
| Technology Advancements – Renewables and DER | As more DER is connected to the grid, hosting capacity available for additional DER diminishes, causing customer interconnection costs to increase for future installations. | If the grid is able to handle two-way power flow by building capacity and using advanced monitoring and automation to manage DER, then DER can become a "tool in the toolbox" for grid operators. |
| Grid modernization | Current technology on the grid does not enable two-way power flow or voltage and power flow optimization needed to handle customer-sited, intermittent generation. This limits the ability for the grid to handle increasing capacity of DER. | With the use of advanced grid technologies (e.g. microprocessor based equipment), the grid could become a platform to connect and proactively use customer DER. |
| Customer Expectations | Customer satisfaction will decrease if customers are not given the option to connect DER, particularly renewables or EVs. If DER is not integrated properly, voltage fluctuations will cause DER to be curtailed. | If DER could be integrated, customers will have more energy options and be able to meet their individual needs such as to reduce greenhouse gases and reduce costs from what they would otherwise be. |
| Environmental Commitments | If customers, particularly corporations and governments, cannot interconnect renewable DER they will not meet their environmental goals. | By allowing customers to interconnect renewable generation, North Carolina will continue to be attractive to businesses with environmental commitments—this includes fast-growing sectors such as data centers, healthcare, and advanced manufacturing. |
| Impact of Weather Events | Grid-connected microgrids and other DER options for resiliency would not be able to be interconnected and used during severe weather events. | Customers will be able to leverage customer-owned resources in outages to improve resiliency by providing power in an outage at a local level. |
| Threats to Grid Infrastructure | Without proper protections, new "points of entry" that pose new cyber attack threat points, i.e. hacking a third-party resource, could impact the grid. | Duke Energy can work proactively with customers to build in protections upfront and over time as needs evolve. |

When will implication occur under BAU? 2018 — 2028

Level of severity of implication: = Manageable = Some Issues = Many Issues

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# IV. REDUCED ABILITY TO MEET CUSTOMER EXPECTATIONS AND COMMITMENTS

DUKE ENERGY

## Business as usual will limit customer options, resulting in higher costs and lower reliability.

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | As the demographics of customers in urban and suburban load growth areas evolve they place a higher priority on uninterrupted and personalized energy service. Strained traditional systems in these areas will not be able to meet customer expectations. | Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building capacity for two-way power flow enables options and grid resiliency. |
| Technology Advancements – Renewables and DER | Under business as usual costs of customer interconnection will increase and curtailment and/or moratoriums will eventually be required which will not meet customer expectations for renewables and DER. | Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will reduce need for curtailment or moratoriums and decrease the cost of interconnection from what they would otherwise be. |
| Grid Modernization | "Like for like" replacement of technology will not lower costs or improve reliability beyond what it is today because capabilities will be unchanged. Further, lack of visibility and control to customer-sited assets and outages will increase cost and reduce reliability. | Distribution automation, grid intelligence and other advanced technologies will minimize outages, accelerate power restoration, and open the opportunity to use DER. |
| Customer Expectations | Customers will be unhappy if expectations for affordability, reliability, and options are not met. | Access to new capabilities and offerings, as enabled by enhanced grid capabilities, enable customers to meet their expectations, encourage their participation in energy decisions and gives them more control over their energy use. |
| Environmental Commitments | The grid will increasingly have less ability to integrate DER and renewables which will cause customers to miss meeting their environmental commitments. | With enhanced grid capabilities, such as increased hosting capacity and the ability to integrate two-way power flow and intermittent resources (such as renewables), customers can meet their commitments with DER including solar, storage and EVs. |
| Impact of Weather Events | Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity. Increasing frequency of outages and increased costs lead to lower customer satisfaction. | By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, occurrence and duration of outages and associated costs can be reduced from what they would otherwise be. |
| Threats to Grid Infrastructure | Absent adequate protection against modern threats, customers will see increased costs and outages due to increased attacks. Increasing frequency of outages and increased costs lead to lower customer satisfaction. | By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack. |

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some issues = Many issues

# V. REDUCED ECONOMIC COMPETITIVENESS FOR NORTH CAROLINA

DUKE ENERGY

## Business as usual makes North Carolina less attractive for businesses and residents.

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | Growth will not be absorbed cost-effectively, thus increasing costs to all customers which drives North Carolina to be a less attractive place to live or do business. Additionally, businesses will be deterred from locating in urban areas (where employees are located) due to reliability issues. | Advanced grid technologies and grid capacity deployed in concentrated growth areas and throughout the system will help to maintain affordability across all customers and encourage business development and relocation to the State. |
| Technology Advancements – Renewables and DER | Due to the inability of the grid to handle increasing amounts of DER, options will be limited for businesses to deploy renewables and/or DER which will make the State less attractive for businesses that desire these options. | Advanced technologies such as advanced monitoring and controls and solutions that increase hosting capacity will allow more DER and renewables making it an attractive market for certain companies. |
| Grid Modernization | Businesses will not be attracted to do business in North Carolina if the electric grid is not reliable or energy costs are less affordable due to existing equipment and operations. Further, prospective businesses may perceive North Carolina as not embracing rapidly advancing technologies. | A more resilient, reliable and intelligent grid will represent a modern, competitive energy system to current and prospective employers and their employees. |
| Customer Expectations | Customer satisfaction will decrease if expectations of affordability, reliability and options are not met, which could lead to residents and businesses choosing not to locate in the State. | Programs to protect, modernize and optimize the grid will provide reliable operation and offer customers the options they seek. |
| Environmental Commitments | The inability to utilize DER to meet environmental goals could inhibit commercial and industrial growth in North Carolina, particularly from large corporations with high renewable energy goals and environmental commitments. | Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for customers to pursue their environmental and sustainability commitments and be interested in North Carolina. |
| Impact of Weather Events | Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase in number and severity resulting in decreased business and consumer confidence in the ability to stay open during storms. | By proactively hardening the system; undergrounding or hardening the most outage prone lines; and building advanced monitoring, control and grid intelligence; the occurrence and duration of outages and associated costs can be reduced helping customers be confident they can do business in an areas subject to storms. |
| Threats to Grid Infrastructure | Absent adequate protection against modern threats, customers will see increased costs and potential outages due to increased attacks resulting in decreased business and consumer confidence. | By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack helping customers be confident they can do business despite threats. |

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some Issues = Many Issues

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# VI. INCREASED GEOGRAPHIC AND DEMOGRAPHIC DISPARITY

DUKE ENERGY

## Business as usual will not adequately meet the needs of rural customers in the future.

| Megatrend | BAU Threat | Opportunity |
|---|---|---|
| Concentrated Growth | Capital demands to meet system expansion in high growth areas can undermine investment in rural areas of the state causing disparity between customer demographics and geography. | Advanced system controls, intelligence, planning, and automation would improve overall system efficiency using existing and new assets and thus improve reliability for all customers. Building grid capacity and the ability for two-way power flow enables options and grid resiliency. |
| Technology Advancements – Renewables and DER | Growth and demographic trends suggest that DER will predominate in urban and suburban centers that have an increasingly younger and higher-wealth demographic, leading to a lesser participation from and cost shifting to lower income or rural customers. | Advanced tools and technologies will enable greater application of DER on the grid. Effectively planning for and optimizing the installation of DER on the grid will lower costs for all customers from what they would otherwise be while maintaining safe and reliable operation of the grid. |
| Grid Modernization | Under business as usual, capital allocated for traditional system improvements necessarily goes to areas where there is highest load and customer count. As a result, rural areas see less timely improvements to the grid under legacy practice using traditional technology. | By optimally implementing new capabilities that reduce costs of improvements and operations in constrained urban areas, additional focus can be given to improvements in rural areas. In addition, grid automation will enhance ability to serve remote areas of the system. |
| Customer Expectations | Business as usual will not allow all customer classes to equally address their expectations for affordability, reliability and options. | Additional capabilities and programs can be used to proactively address the needs of all customer classes and open new opportunities for all customers. |
| Environmental Commitments | Under business as usual, only certain customers and businesses will be able to deploy DER or renewables needed to meet their commitments. | Advanced grid technologies that increase hosting capacity and help to manage intermittency of renewable energy will make it possible for all customer to have access to more DER or renewables. |
| Impact of Weather Events | Absent resiliency and reliability improvements, customers will see increased costs and outages as storms and major weather events increase. This is particularly challenging in rural areas where cost and times for repairs are higher due to longer radials and distance for crews to cover. | By proactively hardening the system, undergrounding or hardening the most outage prone lines, and building advanced monitoring, control and grid intelligence, the occurrence and duration of outages and associated costs can be reduced, particularly in hard-hit rural areas. |
| Threats to Grid Infrastructure | Absent adequate protection against modern threats, customers may see increased costs and outages due to increased attacks. In particularly, physical attacks will be more detrimental in radial systems, particularly in rural areas, due to singular failure points. | By building cyber and physical protections that go beyond current compliance requirements to anticipate threats of the future, customers will be better protected from disruptions and costs of attack in rural areas. |

When will implication occur under BAU? 2018 2028

Level of severity of implication: = Manageable = Some issues = Many issues

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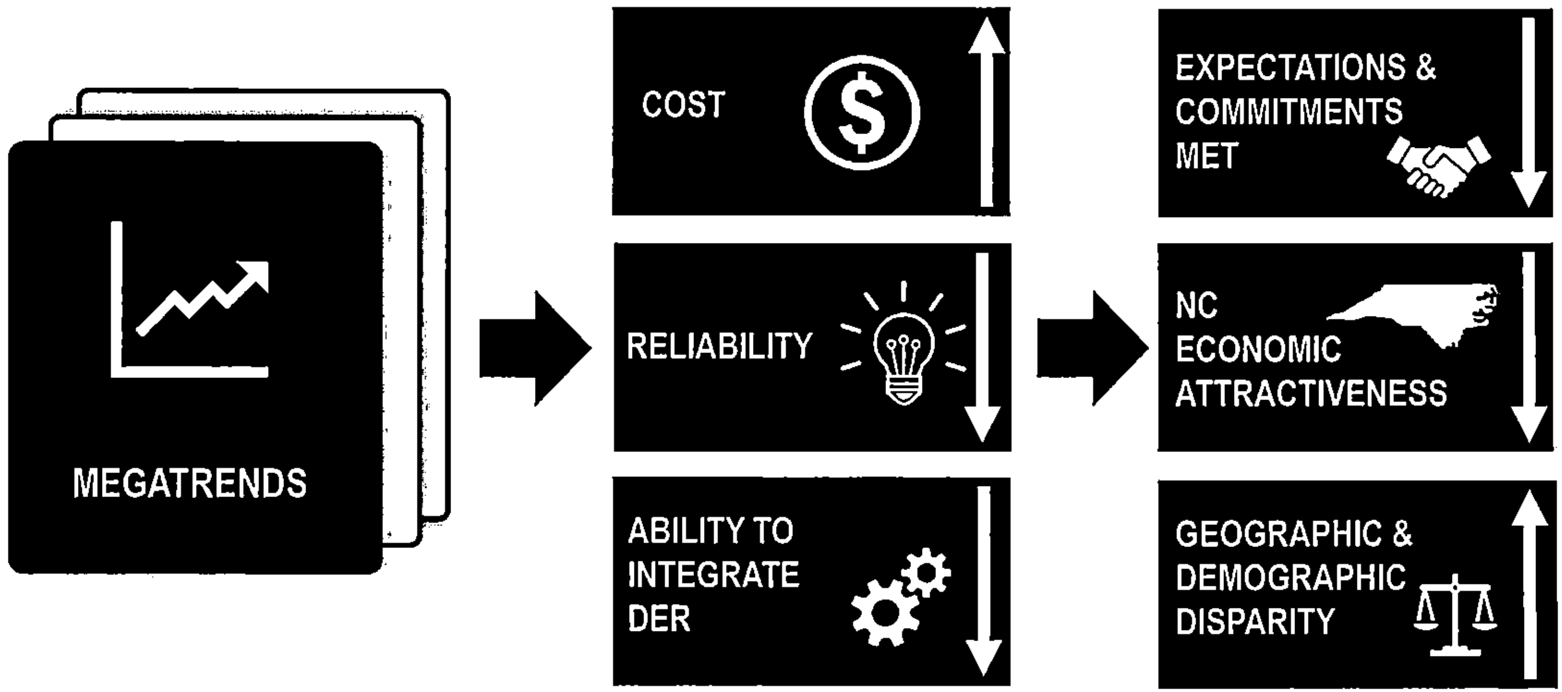
# IMPLICATIONS OF MEGATRENDS

DUKE ENERGY

In summary, evolving megatrends will have implications on our customers and the State.

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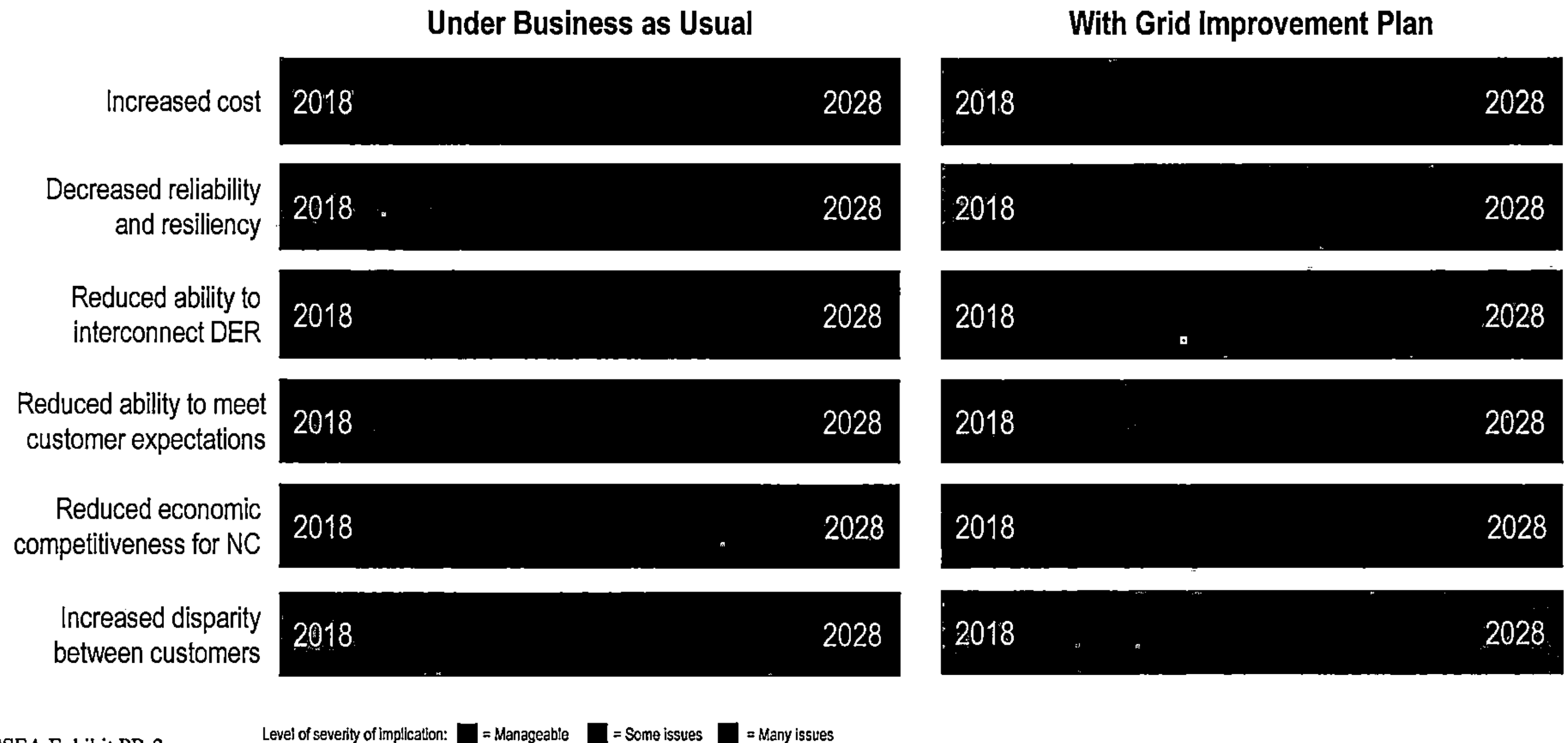
# IMPACT OF GRID IMPROVEMENT PLAN ON IMPLICATIONS

DUKE ENERGY

**Over time, the Grid Improvement Plan will reduce the degree of severity of the implications experienced under business as usual.**



DUKE ENERGY

NORTH CAROLINA GRID IMPROVEMENT PLAN

# PORTFOLIO PRIORITIZATION METHODOLOGY

## FOR STAKEHOLDER WORKSHOP

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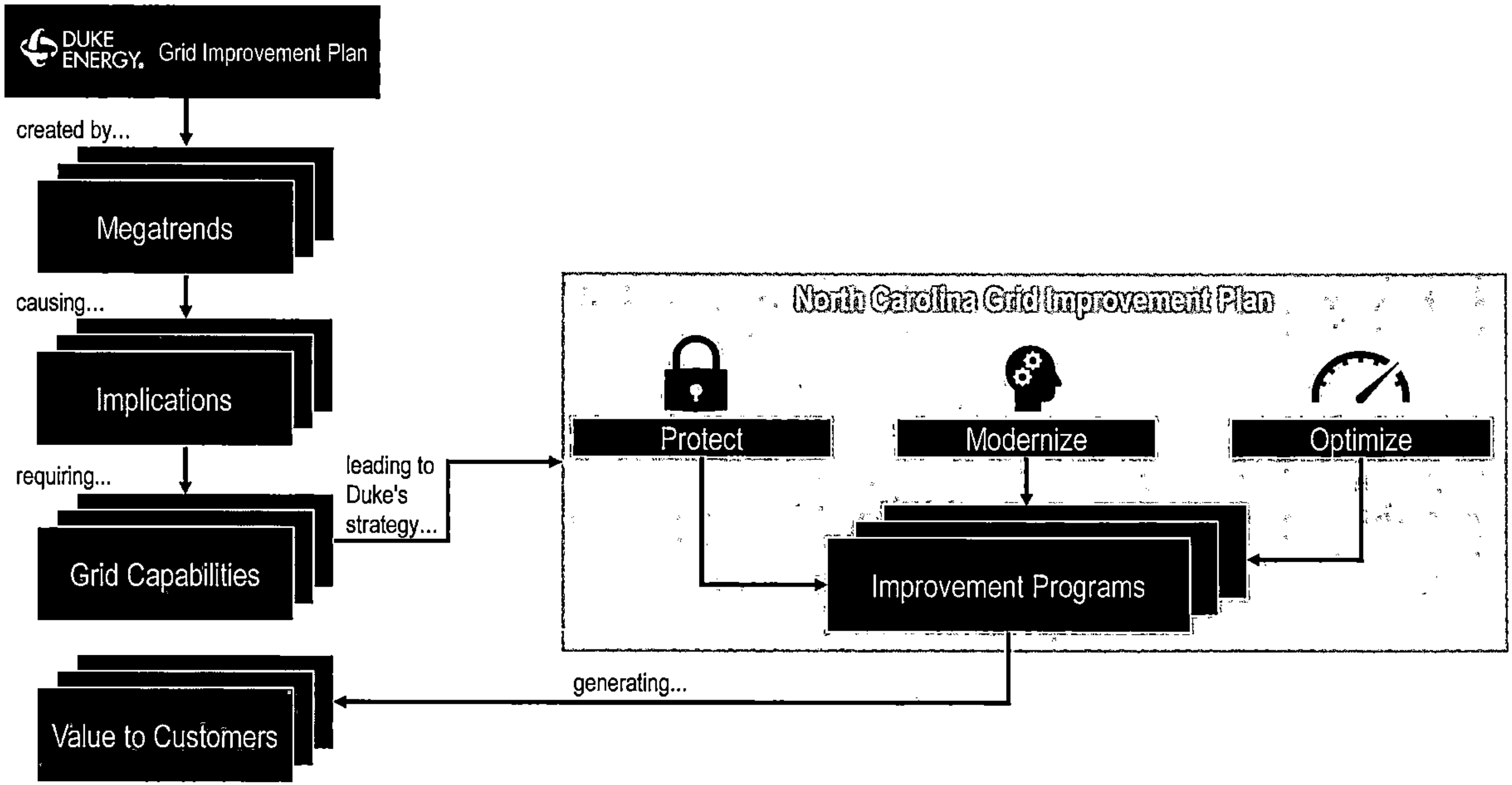
# NORTH CAROLINA GRID IMPROVEMENT PLAN

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# DUKE ENERGY'S NC GRID IMPROVEMENT PLAN FRAMEWORK

DUKE ENERGY

## OPTIMIZE

Optimize the total customer experience

## MODERNIZE

Leverage enterprise systems and technology advancements

## PROTECT

Reduce threats to the grid

## MAINTAIN[1]

Serve customers in a manner that meets industry safety, reliability and environmental standards

(1) *Maintain* base work not included in NC Grid Improvement Plan

# DUKE ENERGY'S NC GRID IMPROVEMENT PLAN FRAMEWORK

DUKE ENERGY



## OPTIMIZE

Optimize the total customer experience

| | | | | | |
|---|---|---|---|---|---|
| Energy Storage | EV Charging | Hardening and Resiliency [T] | Hardening and Resiliency [D] | Integrated Volt-Var Control | Long Duration Interruptions |
| Oil Breaker Replacement | Self-Optimizing Grid | Targeted Undergrounding | Transformer Retrofit | Transformer Bank Replacement | |

## MODERNIZE

Leverage enterprise systems and technology advancements

| | | | | |
|---|---|---|---|---|
| Advanced Metering | DER Dispatch Tool | Distribution Automation | Enterprise Applications | Enterprise Communications |
| Customer Data Access | Integrated System Operations Planning | Power Electronics | Transmission System Intelligence | |

## PROTECT

Reduce threats to the grid

Physical & Cyber Security

## MAINTAIN[1]

Serve customers in a manner that meets industry safety, reliability and environmental standards

| | | | | |
|---|---|---|---|---|
| Line Extensions | Capacity Expansions | Substation Additions | Outage Follow-up | Pole Replacements |
| Vegetation Management | End-of-life Asset Replacement | Equipment Inspection & Maintenance | General System Protection | |

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(1) *Maintain* base work not included in NC Grid Improvement Plan

# DEFINITIONS FOR JUSTIFICATION METHODOLOGIES

DUKE ENERGY



## Cost-Benefit and Cost-Effectiveness Justified (Optimize)

Programs and projects in this category provide customers more net benefits than net costs and solve for one or more external "megatrends."

## Rapid Technology Advancement-Cost Effectiveness Justified (Modernize)

Equipment, software, hardware, operating systems, and/or accepted system operating practice has advanced at an atypical pace in this category causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached operational and price point maturity. While not technically compliance work, work in this category is essential for modern system operations.

## Compliance-Cost Effectiveness Justified (Protect)

i. An external law, rule, or regulation applicable to the company requires the work;

ii. A binding legal obligation such as a contract, agency order, or other legal document compels the work; or

iii. The Operations Council has approved the work as being critical and imperative to the Company's operations

## Maintain Base (Maintain)

Programs and investments to serve customers in a manner that meets industry safety, reliability, and environmental standards.

# PORTFOLIO PRIORITIZATION METHODOLOGY

DUKE ENERGY



**The programs in our portfolio were selected based on alignment with our framework and prioritization criteria.**

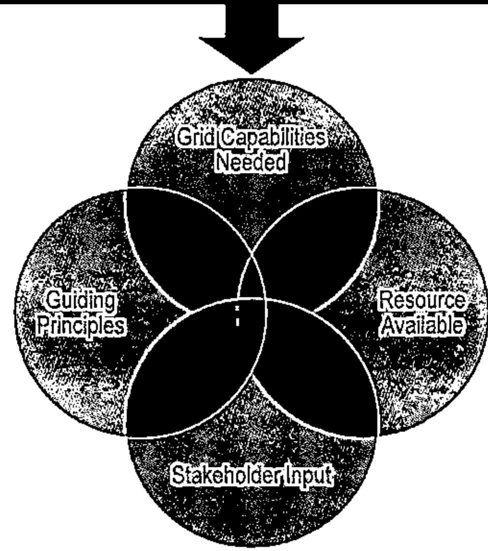
### North Carolina Grid Improvement Plan

| OPTIMIZE |
| --- |
| Optimize the total customer experience |

| MODERNIZE |
| --- |
| Leverage enterprise systems and technology advancements |

| PROTECT |
| --- |
| Reduce threats to the grid |

Megatrends and Implications




Programs are considered based on fit with framework and justification methodology:

- **Protect**: required for compliance
- **Modernize**: technology has rapidly advanced and is now mature
- **Optimize**: program provides attractive benefits

Customer-Focused Programs are selected and funded based on:

- **Grid capabilities** that are needed to address megatrends
- Scope and budgets right-sized to **available resources**
- **Stakeholder input**
- Alignment with **guiding principles**

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# PROGRAM PORTFOLIO

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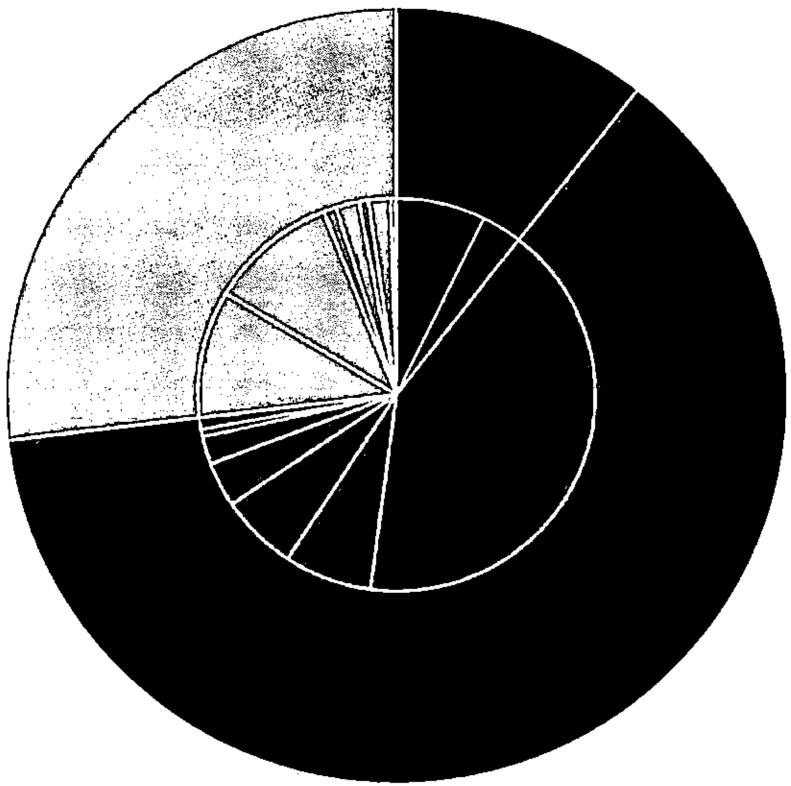
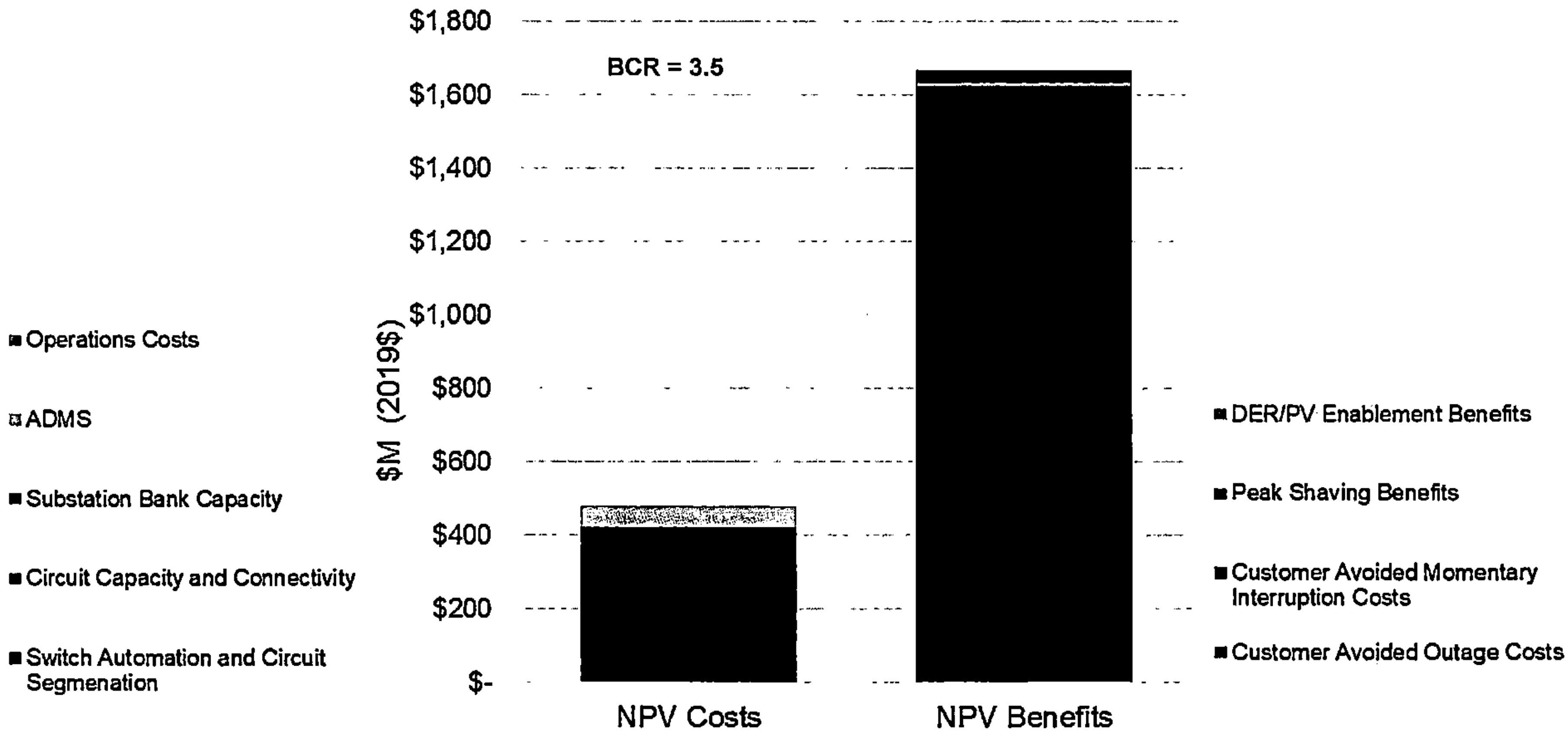


| Program |
|---|
| **Compliance: Cost Effectiveness Justified** |
| Physical Security |
| Cyber Security |
| **Cost Benefit & Cost Effectiveness Justified** |
| SOG |
| Distribution H&R |
| IVVC DEC |
| Transmission H&R |
| TUG |
| Energy Storage |
| Transmission Bank Replacement |
| D-OIL Breaker Replacements |
| T-OIL Breaker Replacements |
| DSDR peak shaving to CVR in DEP |
| **Rapid Technology Advancement: Cost-Effectiveness Justified** |
| T&D Communications |
| Distribution System Automation |
| Transmission System Automtation |
| T&D Enterprise Systems |
| ISOP |
| DER Dispatch Tool |
| Electric Vehicle Charging |
| Power Electronics for volt/var control |
| Customer Data Access |

# SOG 3-YEAR DEPLOYMENT – NPV OF BENEFITS AND COSTS

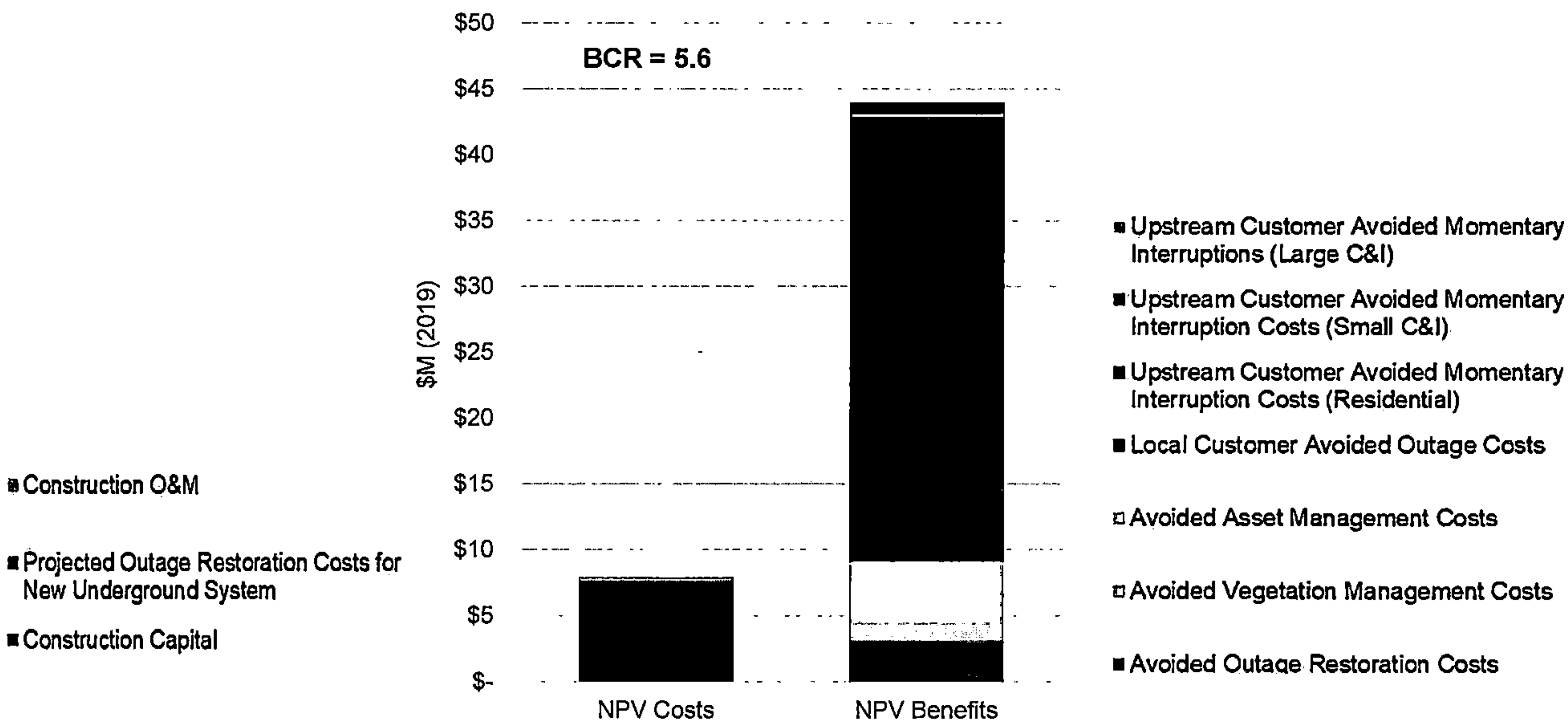
DUKE ENERGY





# TUG WINDSOR PARK DEPLOYMENT – NPV OF BENEFITS AND COSTS

DUKE ENERGY

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DUKE ENERGY



NORTH CAROLINA GRID IMPROVEMENT PLAN

# PROGRAM SUMMARIES

## FOR STAKEHOLDER WORKSHOP

11/08/18

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DUKE ENERGY

# PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)

DUKE ENERGY

**The IVVC program establishes control of distribution equipment in substations and on distribution lines to optimize delivery voltages to customers and power factors on the distribution grid.**

## DESCRIPTION

IVVC allows the distribution system to optimize voltage and reactive power needs. The program employs remotely operated substation and distribution line devices such as voltage regulators and capacitors. The settings for thousands of these controllable field devices are optimized and dispatched via a distribution management system.

IVVC capabilities enable a grid operator to lower voltage as a way of reducing peak demand (peak shaving), thereby reducing the need to generate or purchase additional power at peak prices, or protecting the system from exceeding its load limitations. The current DEP **Distribution System Demand Response (DSDR)** program uses the peak shaving mode of IVVC to support emergency load reduction.

Another operational mode enabled by IVVC capabilities on the distribution system is **Conservation Voltage Reduction (CVR)**. CVR uses IVVC during periods of more typical electricity demand to reduce overall energy consumption and system losses.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

## MORE ABOUT THE PROGRAM

The Distribution Management System (DMS), which manages the dispatch of IVVC functionality, can be designed to manage distribution circuits such that any impacts to customers with large motors sensitive to voltage control can be reduced. To maximize operational flexibility and value, the IVVC system can also have peak shaving capability and emergency modes of operation. Advanced DMS software upgrades will enable IVVC to operate in various modes to provide further customer benefit in the future.

### DSDR to CVR in DEP

In 2014, Duke Energy implemented DSDR in DEP, achieving peak shaving voltage reduction of approximately 3.6% across the DEP distribution system. The DMS in DEP is capable of optimized modes (i.e., DSDR) or non-optimized (i.e., emergency) modes. When in emergency mode, the system can quickly provide a temporary voltage reduction capability of up to 5.0%.

DEP's initial implementation of DSDR also included a significant amount of circuit conditioning to optimize the system for DSDR mode (i.e., the installation of voltage regulating devices and capacitors, balancing of load on distribution circuits, and reconductoring of some distribution lines to larger wire sizes).

Because the substation, distribution, telecommunications, and IT infrastructure were put in place as part of the original DSDR implementation, this sub-program focuses on the deployment of the few additional device installations as well as the DMS upgrades required to support various operational modes, including the current DSDR mode and CVR mode, as well as Self Optimizing Grid and other distribution automation capabilities.

Through this sub-program, Duke Energy will enable 2% voltage reduction for energy conservation (an average of roughly 1.4% load reduction).

### IVVC Project in DEC

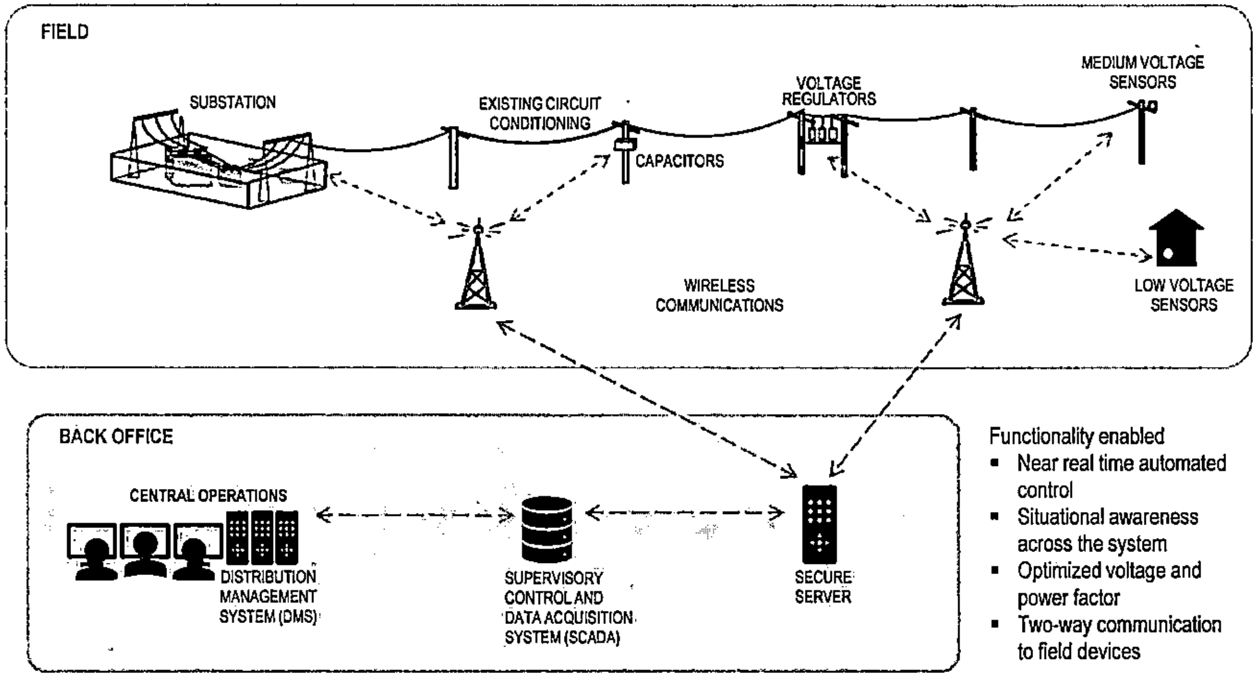
The DEC IVVC pre-scale deployment project used real-time field conditions on a small scale to demonstrate the use of IVVC on the DEC system, and validate benefits in advance of its full-scale rollout. The small-scale demonstration validated voltage reductions of approximately 2% are possible with appropriate transmission and distribution system upgrades.

The DEC IVVC project will install communications and voltage control infrastructure at substations and associated distribution lines. The project will also leverage overlaps with efforts like Self Optimized Grid projects that deploy some of the infrastructure and capabilities necessary to enable IVVC.

# PROGRAM: INTEGRATED VOLT/VAR CONTROL (IVVC)

DUKE ENERGY

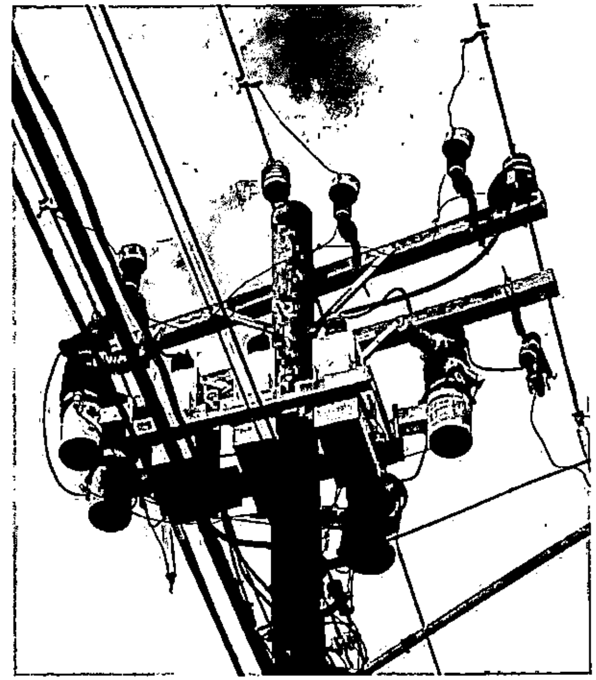





Functionality enabled

- Near real time automated control
- Situational awareness across the system
- Optimized voltage and power factor
- Two-way communication to field devices

**SMART CAPACITOR BANK**



# PROGRAM: SELF-OPTIMIZING GRID (SOG)

DUKE ENERGY

**The self-optimizing grid program, also known as the smart-thinking grid, redesigns key portions of the distribution system and transforms it into a dynamic self-healing network.**

## DESCRIPTION

The current grid has limited ability to reroute or rapidly restore power and limited ability to optimize for the growing penetrations of distributed energy resources (DER). The SOG program is established to address both of these issues.

The SOG program consists of three (3) major components: grid capacity, grid connectivity, and automation and intelligence. The SOG program redesigns key portions of the distribution system and transforms it into a dynamic smart-thinking, self-healing grid. The grid will have the ability to automatically reroute power around trouble areas, like a tree on a power line, to quickly restore power to the maximum number of customers and rapidly dispatch line crews directly to the source of the outage. Self-healing technologies can reduce outage impacts by as much as 75 percent.

The **SOG Capacity projects** focus on expanding substation and distribution line capacity to allow for two-way power flow. **SOG Connectivity projects** create tie points between circuits. **SOG Automation projects** provide intelligence and control for the Self Optimizing Grid. Automation projects enable the grid to dynamically reconfigure around trouble and better mange local DER.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

# PROGRAM: SELF-OPTIMIZING GRID (SOG)

DUKE ENERGY

## MORE ABOUT THE PROGRAM

The SOG program, also known as the smart-thinking or self-healing gird, implements distribution system design guidelines that improve grid reliability and resiliency. SOG circuits will have automated switches to divide the circuit into switchable segments. Each segment is designed to consist of approximately 400 customers, three miles in circuit segment length, or serve 2MW of peak load. This design ensures that any issues on the system can be isolated, and customer impacts are limited. The long term vision is to serve 80% of customers by the Self-Optimizing Grid.

### Advanced Distribution Management System (ADMS)

The ADMS subprogram is an enterprise-wide program to deploy a common distribution management system. Consolidating to a single platform for DMS and SCADA systems enables operational efficiency and the ability to integrate future solutions needed as demands on the distribution system evolve. The three main projects are: (1) **SCADA upgrade project** which upgrades the supervisory control and data acquisition system; (2) **DMS common platform project** which deploys a common version of DMS across DEC and DEP; and (3) **Closed loop FLISR project** which deploys DMS functionality that minimizes the area impacted by the resulting outage.

### SOG Segmentation & Automation

This subprogram focuses on segmenting circuits in accordance with SOG design guidelines (segments should serve approximately 400 customers, are three miles in length or serve 2 MW of peak load) and equipping those segments with automated switching devices. The purpose is to limit the exposure of customers to power outages associated with faults on a line (e.g., a tree falling or vehicle-power pole collision). This is accomplished by sectionalizing a circuit by adding and/or re-configuring a number of protective devices on tap lines.

### Circuit Capacity and Connectivity

This subprogram focuses on upgrading selected circuit feeders and tying them together to meet the SOG design philosophy. The circuit capacity activities involve upgrading the feeder conductor and voltage control devices to enable a circuit to carry its own customer load as well as portions of adjacent circuit customer load, as needed.

### Substation Bank Capacity

This subprogram focuses on upgrading selected substations to meet the SOG design philosophy. The substation bank capacity activities involve upgrading existing substation transformers and other associated equipment to allow for a substation to service its normal customer load as well as any additional load it may pick up during a SOG isolation/reconfiguration event.

# PROGRAM: POWER ELECTRONICS FOR VOLT/VAR

DUKE ENERGY

**The Power Electronics program integrates protection and control technology, helps reduce power quality issues associated with high DER penetration, and ultimately improves reliability to customers.**

## DESCRIPTION

As the adoption of distributed energy resources (DER) (e.g., customer-owned solar and energy storage) reaches critical levels and microgrid technology matures, protective device technology must also advance to appropriately detect and respond to rapid voltage and power fluctuations that often accompany non-dispatchable resources such as solar.

As clouds move across the daytime sky and momentarily block sunlight from reaching solar panels, solar generation immediately ceases. As sunlight peaks through openings in the cloud cover, the solar panels begin generating, creating power spikes and voltage instability on the circuit. These intermittent power impacts occur and then change at rapid rates (in some cases sub-second) and frequently faster than the legacy electro-mechanical voltage management equipment like regulators and capacitors can handle.

Integrating advanced solid-state technologies like power electronics (i.e., static VAR compensators and other solid-state voltage support equipment), better equips the distribution system to manage power quality issues associated with increasing DER penetration.

The program is still in its early stages and current plans are small pre-scale deployments to validate capabilities and benefits.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

## VALUE TO OUR CUSTOMERS

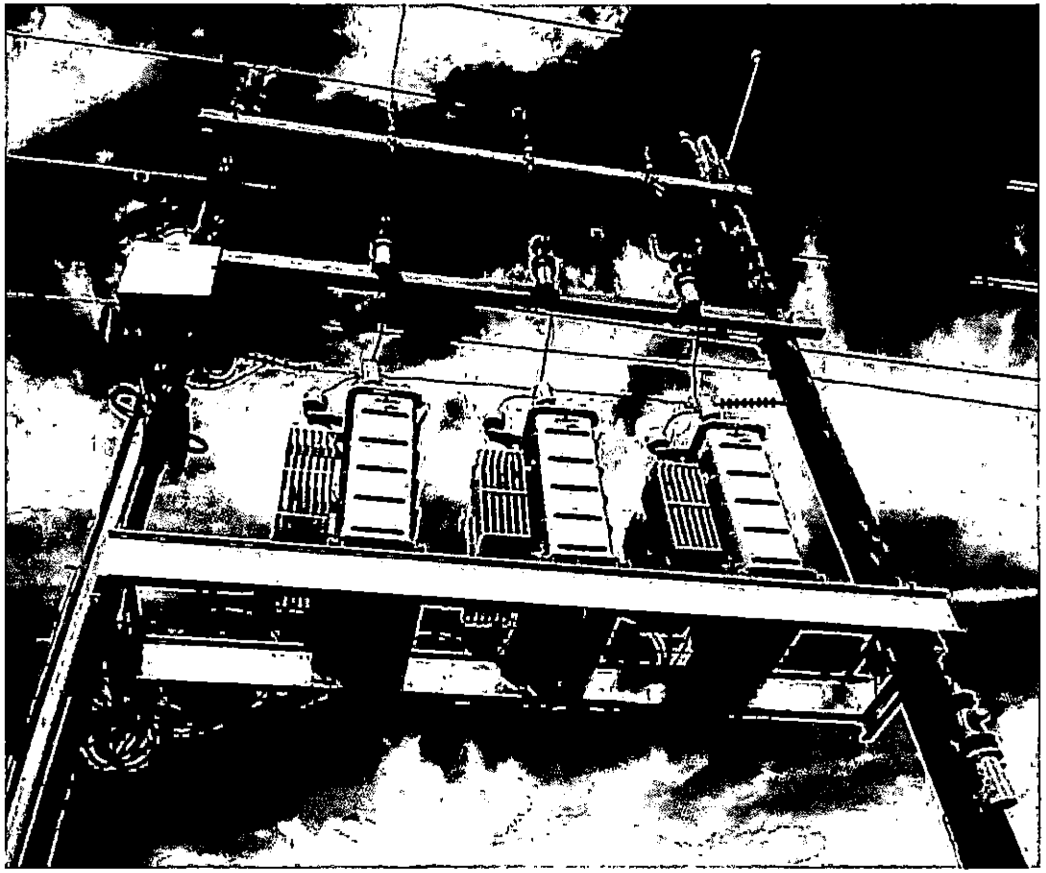
- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: POWER ELECTRONICS FOR VOLT/VAR

DUKE ENERGY



**FIRST INSTALLATION OF MINIDVAR IN DEP TERRITORY**

COST-EFFECTIVE UPGRADE FOR FEEDERS WITH HIGH SOLAR PV OR DG GROWTH

# PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

DUKE ENERGY



**The DA program improves how the distribution system protects the public and itself from unsafe voltage and current levels and significantly reduces the impact experienced by customers due to grid issues.**

## DESCRIPTION

The capabilities offered through DA can transform what may have been an hour-long power outage for hundreds or even thousands of homes and businesses into a momentary outage – or potentially help avoid an outage altogether.

The DA consists of several complementary efforts that work in concert to support dynamic and growing distribution system loads in a more sustainable way while minimizing power quality issues that often accompany a large-scale transition to solar power. One of these projects, **Urban Underground System Automation,** modernizes the protection and control of underground power systems that serve critical high-density areas, such as urban business districts and airports.

The **Fuse Replacement** project focuses on replacing one-time use fuses with automatic operating devices capable of intelligently resetting themselves for reuse, thus eliminating unnecessary use of resources (inventory, time, gasoline, etc.). The **Hydraulic to Electronic Recloser** program replaces obsolete oil-filled (hydraulic) devices with modern, remotely operated reclosing devices that support continuous system health monitoring.

Such digital device upgrades offer further value through efforts like the **System Intelligence and Monitoring** pilot, which develops advanced diagnostic tools that help engineers and technicians address electrical disturbances on the distribution system and improve customer experience.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: DISTRIBUTION SYSTEM AUTOMATION (DA)

DUKE ENERGY



## MORE ABOUT THE PROGRAM

Through its suite of complementary efforts, the DA Program offers a way to deliver electricity to customers while avoiding preventable service interruption for thousands of customers.

**Hydraulic to Electronic Recloser**

Phases out existing hydraulic (oil-filled) reclosers to reduce the oil footprint and eliminate maintenance activities. The sub-program has two phases: (1) target all hydraulic reclosers rated 140 amps or greater and replace with electronic, solid-dielectric interrupter devices; and (2) focus on smaller hydraulic reclosers (those rated less than 100 amps) and replace them with similar electronic, solid-dielectric, reclosing devices as this technology becomes mature enough for full scale deployment.

**System Intelligence and Monitoring Pre-Scale Effort**

Leverages data from digital devices deployed as part of the Self-Optimizing Grid, Smart Meter, and other programs to build a database and system model that monitors electrical disturbances across the distribution system. While each grid device may only monitor a portion of a circuit, advanced analytics creates a larger picture of system activity and an end-to-end blended view of customer experience. When completed, this subprogram will create a new system diagnostic tool for troubleshooting problem areas and mitigating emerging issues as they occur, as well as for managing the integration of DER.

**Fuse Replacements with Electronic Reclosers**

Replaces protective tap line fuses with small electronic sectionalizing devices on segments that can eliminate the most interruptions for customers. The small electronic reclosers serve to prevent customer outages by allowing temporary faults time to clear power lines before operating and initiating sustained outages. A protective fuse in this same tap line configuration is designed to actuate and initiate a sustained line outage at the first sign of a line fault; it must then be replaced before service can be restored. The fuse replacement with electronic recloser eliminates the mainline breaker from operating at all, eliminating unnecessary momentary interruptions and sustained outages.

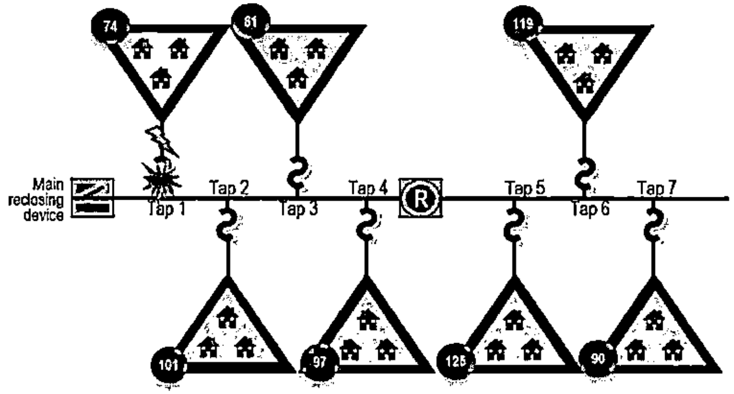
**Underground (UG) System Automation**

Replaces manually operated underground switchgear with remotely operated automated switchgear and deploys advanced automation schemes in urban downtown areas and other places with high density public use, such as airports and public entertainment areas. UG Automation enables automatic reconfiguration of underground systems for connecting to a new feeder or for isolating downstream system faults to minimize customer outages and impacts to the public. When completed, what might have been hours of service interruption can be reduced down to seconds.

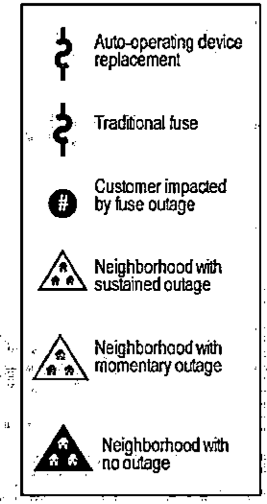
DUKE ENERGY

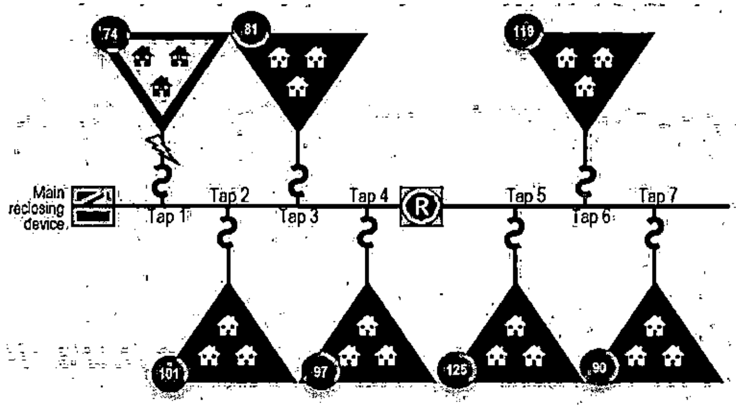


**WITHOUT DEVICE REPLACEMENTS**
(687 momentary interruptions, 74 sustained interruptions, one fuse replacement)




- Temporary fault Tap 1
- Main reclosing devices blinks
- All 687 customers experience a momentary outage
- The 74 customers of neighborhood 1 experience a sustained outage until the Tap 1 fuse is replaced




- Temporary fault Tap 1
- Main reclosing devices blinks
- Only the 74 customers experience a momentary outage
- Auto-operating device resets
- Zero sustained outages; no fuse replacement needed

**WITH AUTOMATICALLY-OPERATING DEVICE REPLACEMENTS**

# PROGRAM: ENERGY STORAGE

**The Energy Storage program implements battery storage and other related non-traditional measures to defer, mitigate, or eliminate the need for traditional utility investments, such as line capacity upgrades.**

## DESCRIPTION

The program supports customer and utility initiatives through smart investments in storage for applications that deliver value to customers and the company. These applications include microgrid projects for preventing planned and unplanned outages, as well as long-duration outage projects for providing redundant power sources for vulnerable (rural and remote) communities, and circuit and bank capacity projects using substation-tied energy storage.

Given the multiple applications energy storage technology supports, projects within the Energy Storage program are designed and assessed on a case-by-case basis for the specific challenge being addressed (e.g., long duration outage support, microgrid or emergency power support, auxiliary service needs, etc.).

The Energy Storage program also includes the development and deployment of an energy storage control system to manage the fleet of energy storage resources.

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY (DER Enablement)
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

## MORE ABOUT THE PROGRAM

Energy storage provides several different forms of value when applied to the distribution grid. It can be used as a tool to improve reliability to remote communities and it can help increase the how much DER in the form of solar energy can be connected to the grid. It can also be used as a way to delay or mitigate the need to invest in more traditional resources to address transmission and distribution capacity needs.

**Energy Storage Control System (ESCS)**

By enabling grid operators to dispatch batteries, and batteries plus solar, as part of a diverse generation portfolio, the ESCS project creates the means for distributed energy resources to provide a more cost-effective, energy storage solutions for enhancing grid efficiency and reliability, along with bulk power operations effectiveness. The primary ESCS applications include: (1) Frequency regulation services, (2) Energy arbitrage (i.e., shifting to charge off-peak, discharge-on peak), and (3) Microgrid islanding for outage support and peak shaving.

**Interrelation with Integrated System Ops Planning (ISOP)**

Energy storage is a technology that offers the ability to support many valued requirements across the generation, transmission and distribution systems. The Integrated System Operation Planning (ISOP) effort will enable storage and microgrid projects to be deployed more effectively.

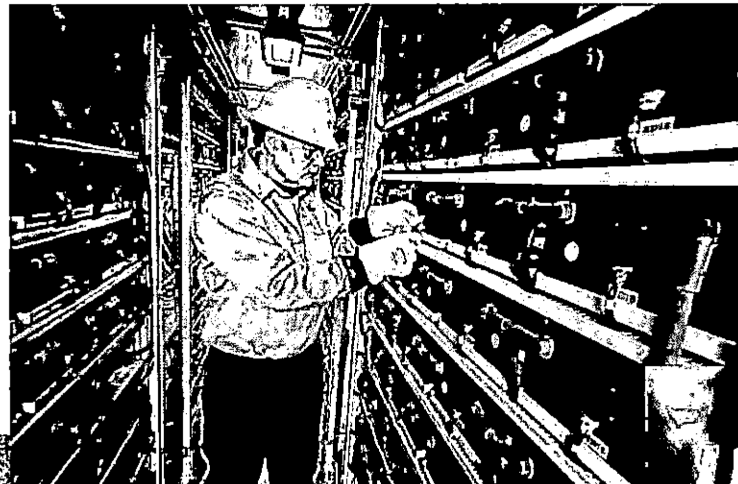
***Example:* Mt. Sterling Microgrid**

The Mt. Sterling Microgrid project was developed to provide electric service to a remote customer in a reliable but more cost-effective way than via a traditional distribution feeder. The microgrid option meets customer needs through use of distributed energy resources, while enhancing both safety and productivity for utility workers by mitigating line maintenance activity in a high-risk, labor-intensive environment. With the maturity of energy storage technology, a microgrid with solar and storage components sized to support customer load for seven consecutive days (without solar generation) was designed, assessed, and determined to be a more reliable and cost effective option for meeting the customer's need for service. The solution, a 10-kW solar PV array, a 95-kWh battery energy storage system and remote monitoring system, offers availability 99.95% of time, with 25-year asset life.

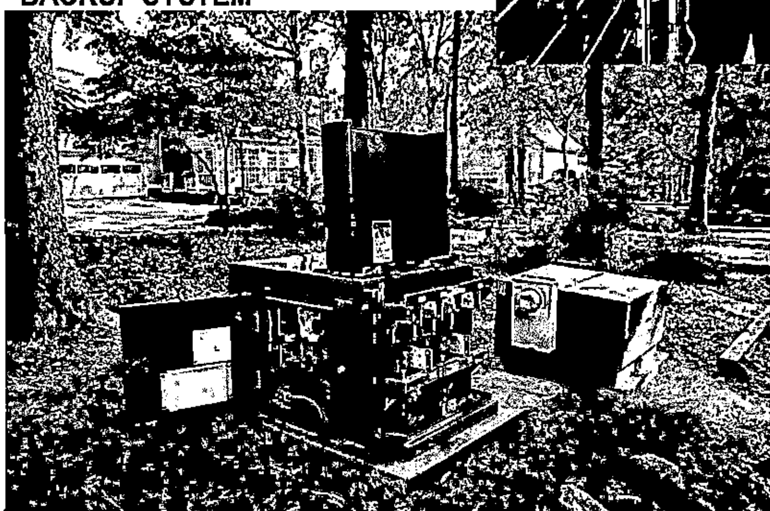
# PROGRAM: ENERGY STORAGE

DUKE ENERGY

MCALPINE MICROGRID BATTERY SYSTEM



COMMUNITY BATTERY BACKUP SYSTEM



NOTREES BATTERY STORAGE FACILITY

NCSEA Exhibit PB-2

# PROGRAM: LONG DURATION INTERRUPTION / HIGH IMPACT SITES (LDI/HIS)

DUKE ENERGY

**The LDI/HIS program is designed to improve the reliability for parts of the grid with high potential for long duration outages as well as for high-impact customers like airports and hospitals.**

## DESCRIPTION

The LDI/HIS program is designed to improve the reliability in parts of the grid where the duration of potential outages is expected to be much higher than average. Focus areas for this program are radial feeds to entire communities or large groups of customers as well as inaccessible line segments (i.e. off road, swamps, mountain gorges, extreme terrain, etc.).

Many of the areas served by these long, rural, single-sourced feeders can experience significant impacts to the local economy and to quality of life when the entire town loses power. Further, operational and repair costs are generally higher than average in these areas due to the special equipment required.

While some sites may include extreme hardening, circuit relocations, new circuit ties and undergrounding, energy storage solutions may offer more cost-effective solutions for improving reliability and managing costs.

The LDS/HIS program is designed to improve the reliability of high- impact customers like airports and hospitals, and high-density areas that could require a variety of infrastructure solutions to improve power quality and reliability. Typical projects include substation upgrades, circuit ties, voltage conversions, and reconductoring.

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY

## VALUE TO OUR CUSTOMERS

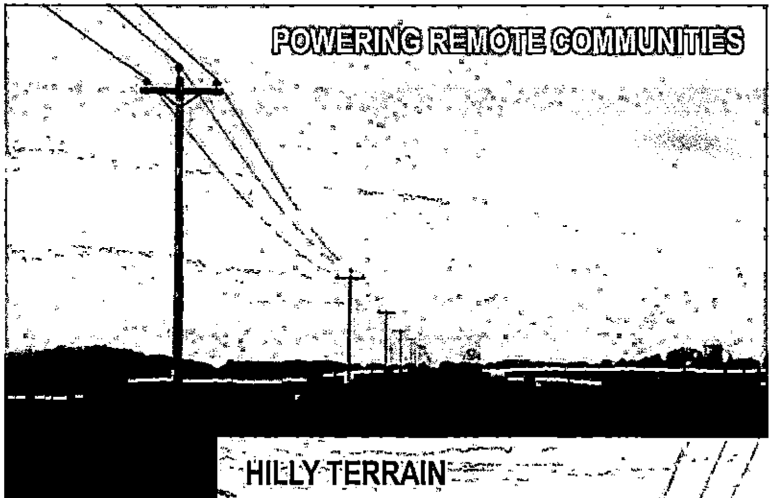
- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

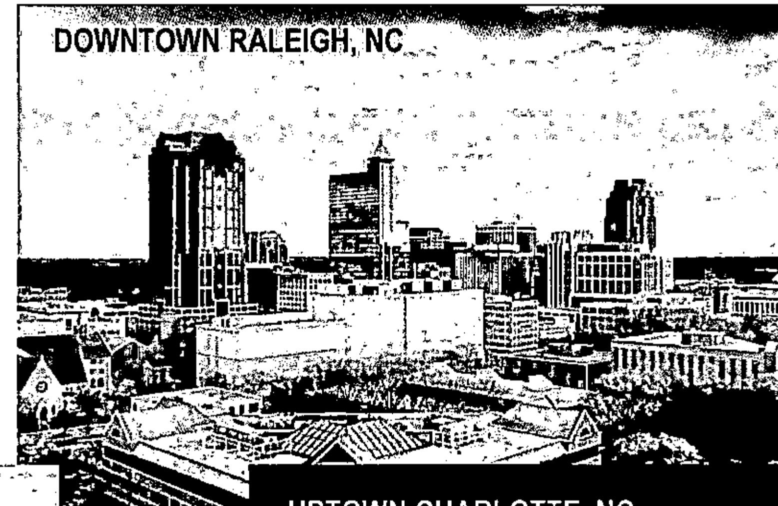
## WHERE IT FITS IN OUR PLAN

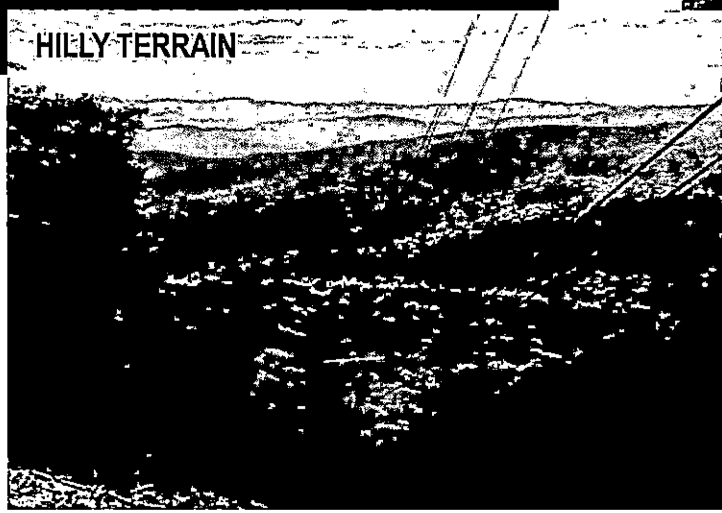
**OPTIMIZE** the total customer experience

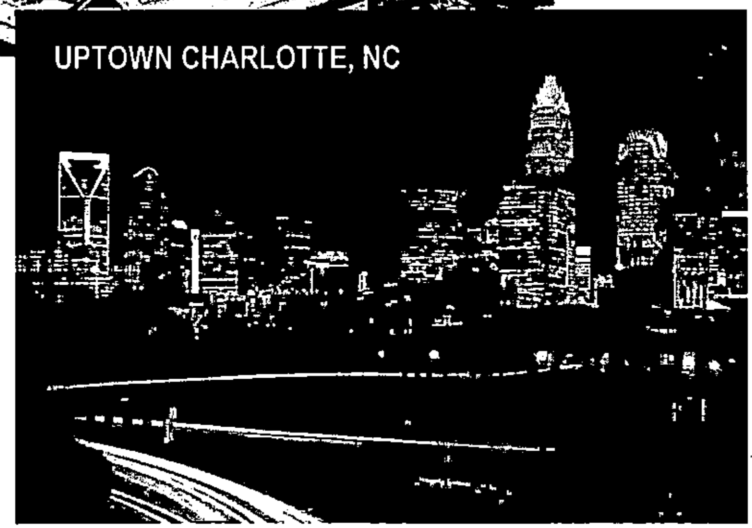
# PROGRAM: LONG DURATION INTERRUPTION / HIGH IMPACT SITES (LDI/HIS)

DUKE ENERGY




NCSEA Exhibit PB-2

# PROGRAM: INTEGRATED SYSTEM OPERATIONS PLANNING (ISOP)

DUKE ENERGY

**The ISOP program integrates utility planning for generation, transmission, distribution, and customer programs to improve the valuation and optimization of energy resources across the system.**

## DESCRIPTION

Requirements for modern electric utility systems are evolving rapidly with the advent of emerging new energy technologies, changes in policy, and rapid advancements in information exchange and customer needs. Integrated System Operations Planning (ISOP) focuses on the integration of utility planning disciplines for generation, transmission, distribution and customer programs to improve the valuation and optimization of energy resources across all segments of the utility system to best serve electric customers.

The ISOP process addresses key operational and economic considerations across all segments of the system through integration and refinement of existing system planning tools and, in some cases, development of new analytical tools to assess characteristics that have not historically been captured or considered in long-term planning. Some examples include locational values for distributed resources, system ancillaries and reserves needed to support future operations, and energy resource flexibility to support new dynamic operational demands on the system.

ISOP is a multi-year development program to build the tools and processes needed to accommodate an increasingly integrated approach that will be required to optimize planning and operation of the electric utility system of the future.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: TARGETED UNDERGROUNDING (TUG)

DUKE ENERGY

**The TUG program strategically identifies Duke Energy's most outage prone overhead power line sections and relocates them underground to reduce the number of outages experienced by customers.**

## DESCRIPTION

Overhead power line segments with a history of unusually high numbers of outages drive a disproportionate amount of momentary interruptions and outages that affect Duke Energy's customers. When these segments of lines fail, they cause problems for Duke Energy's customers directly served by them as well as customers upstream. Lines targeted to be moved underground are typically the most resource-intensive parts of the grid to repair after a major storm. Equipment on these line segments can experience shortened equipment life and additional equipment-related service interruptions.

The goal of the TUG program is to maximize the number of outage events eliminated. Converting outage prone parts of the system enables Duke Energy to restore service more quickly and cost effectively for all customers. Addressing areas with outlier outage performance improves service while lowering maintenance and restoration costs for all customers.

Criteria for consideration in the selection of targeted communities include:

- Performance of overhead lines
- Age of assets
- Service location (e.g., lines located in backyard where accessibility is limited)
- Vegetation impacts (e.g., heavily vegetated and often costly and difficult to trim)

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

# **PROGRAM:** TARGETED UNDERGROUNDING (TUG)

DUKE ENERGY



**DOWNED POWER POLES**

DAMAGE FROM HURRICANE MATTHEW

**LINEMAN IN RAIN**

IN AREAS INACCESSIBLE BY BUCKET TRUCK, LINEMEN HAVE TO CLIMB POLES TO MAKE REPAIR

NCSEA Exhibit PB-2

# PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

DUKE ENERGY



**The Distribution Transformer Retrofit program converts existing overhead distribution transformers to deliver the same reliability benefits as a modern transformer installed today.**

## DESCRIPTION

Like the Self-Optimizing Grid program, the new sectionalization capability of a retrofitted transformer works to minimize the number of customers impacted by fault or failure on the power line. In addition, similar to the Targeted Undergrounding program, the new protective features that mitigate equipment vulnerabilities work to significantly lower the risk of an outage occurring at the transformer all together.

The core activities of the transformer retrofit program include the installation of a fuse disconnect device on the high-voltage side of every overhead transformer to protect upstream customers from a fault at or downstream of the transformer. In addition, through protective device coordination, the local fused disconnect can be set to prevent any upstream operations of reclosing devices (the source of momentary outages for customers not served by the retrofitted transformer.)

Consistent with modern transformer standards, the program also retrofits transformers with additional protective elements to reduce the risk of external factors such as lightning strikes and animal interference.

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

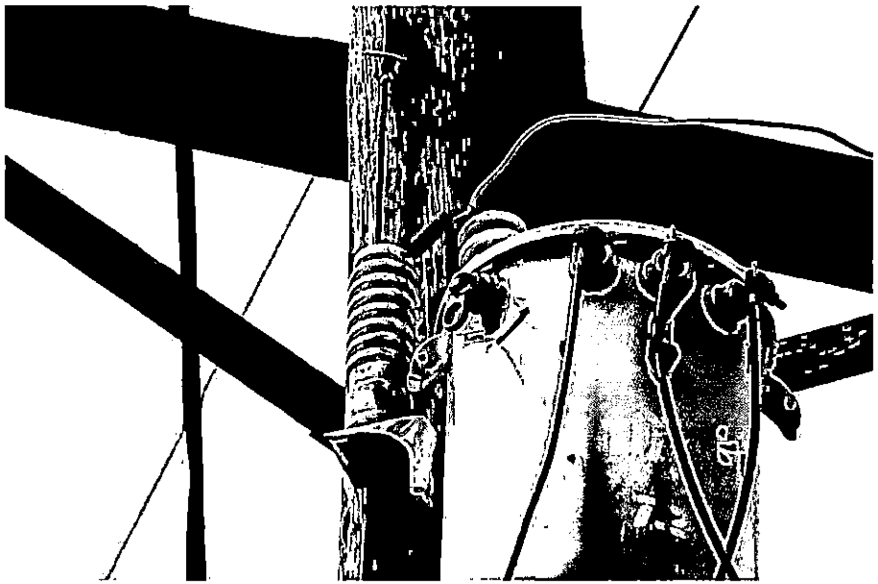
**OPTIMIZE** the total customer experience

# PROGRAM: DISTRIBUTION TRANSFORMER RETROFIT

DUKE ENERGY

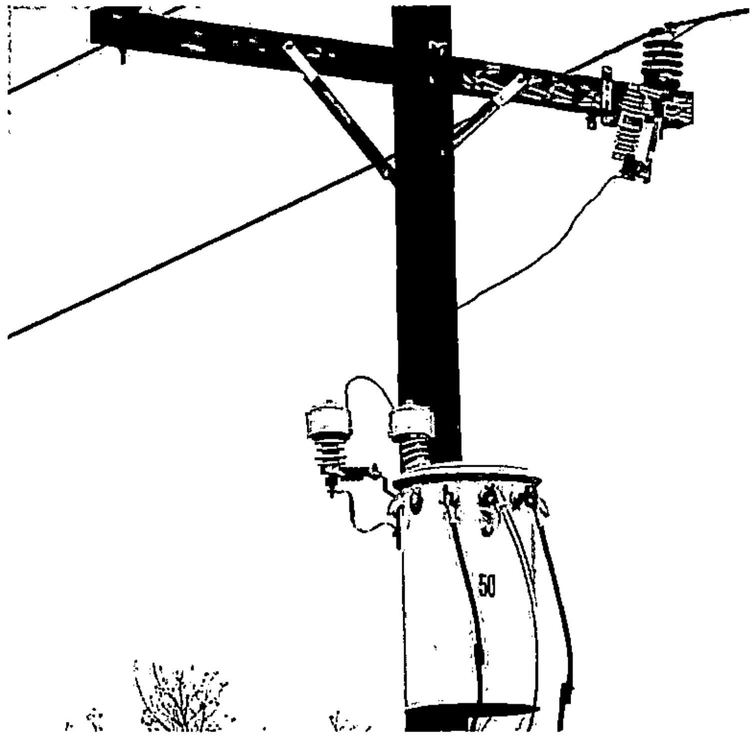


**UN-RETROFITTED CSP TRANSFORMER**



**RETROFITTED TRANSFORMER**

FUSED CUTOUT, ANIMAL GUARDS,
COVERED LEAD WIRE, NEW ARRESTER.



# PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

DUKE ENERGY



**The Distribution H&R – Flood Hardening program will be targeted to areas where an overlay of actual outage events from Hurricanes Matthew and Florence intersect with the 100-year flood plan.**

## DESCRIPTION

In hurricane events like Hurricane Floyd and more recently Hurricanes Matthew and Florence, significant flooding was a major factor impacting restoration. Smart, targeted investments can mitigate the scale of impacts on communities and customers adjacent to these areas prone to extreme flooding. Hardening lines and structures is a balanced approach that can keep power and critical services available to some portion of a community and prevent a widespread outage in an area until flooding recedes.

This program includes the following:

- Alternate power feeds for substations in flood-prone areas, and for radial power lines that cross into and through flood-prone areas
- Hardened river crossings where power lines are vulnerable to elevated water levels during extreme flooding
- Improved guying for at-risk structures within flood zones

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

## MORE ABOUT THE PROGRAM

Data analytics and geo-spatial analysis will assist Duke Energy in identifying patterns of repeat flood impact issues and allow a targeted basis for assessing hardening investments with a cost benefit analysis approach that delivers savings to Duke Energy customers and, at the same time, enhanced reliability for these flood-prone areas.

For a three-year window, this program will focus on hardest hit flood-prone areas from Hurricanes Matthew and Florence, defining opportunities to accomplish the following:

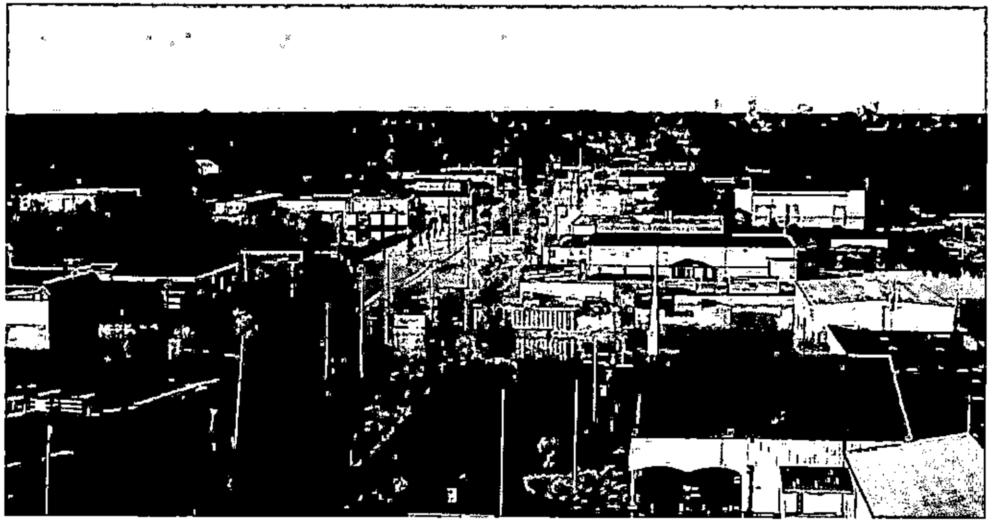
- Event elimination where hardening can demonstrably eliminate future outages events and repair work
- Resiliency options to re-route power and keep many people supplied with power while repairs to damaged facilities are made.

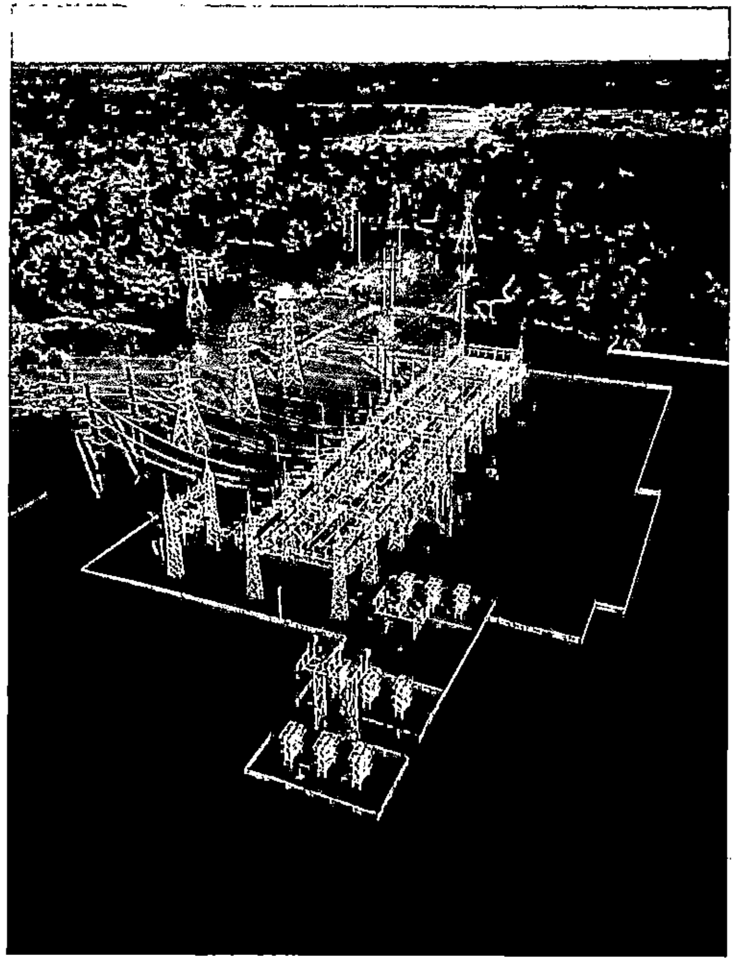
This program will be coordinated with other programs to ensure work scopes do not overlap.

# PROGRAM: DISTRIBUTION HARDENING & RESILIENCY – FLOOD HARDENING

DUKE ENERGY

**GOLDSBORO FLOODING DURING HURRICANE MATTHEW**





FLOODING OF A SUBSTATION IN GOLDSBORO FOLLOWING HURRICANE MATTHEW (2016)

# PROGRAM: SMART METERING INFRASTRUCTURE

DUKE ENERGY

**The Smart Meter program is a metering solution (meters, communication devices and networks, and back office systems) used to create two-way communications between customer meters and the utility.**

## DESCRIPTION

Smart meters are digital electricity meters that have advanced features and capabilities beyond traditional electricity meters. Some of the advanced features include the capability for two-way communications, interval usage measurement, tamper detection, voltage and reactive power measurement, and net metering capability.

Duke Energy's standard smart meter system utilizes a radio frequency ("RF") mesh architecture, which is flexible in that the meters within the mesh network establish an optimized RF communication path to a collection point either through other meters, through network range extenders, or via a direct cellular connection.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: SMART METERING INFRASTRUCTURE

DUKE ENERGY



# PROGRAM: ELECTRIC TRANSPORTATION

DUKE ENERGY





**The Electric Transportation effort is a proposed pilot program for North Carolina that will focus on advancing adoption of electric transportation in the State.**

## DESCRIPTION

The North Carolina program will establish a foundational level of public fast-charging infrastructure to advance electric vehicle adoption and inform best practices for cost-effective integration of various electric vehicle types with the electric system.

The ET pilot program will consist of five components: (1) Residential EV Charging Rebates, (2) Commercial Customer Charging Rebate, (3) Electric School Bus Infrastructure Investments, (4) Electric Transit Bus Infrastructure Investments, (5) DC Fast Charging Infrastructure. The bus components of the program will serve to financially support deployments of electric school and transit buses in conjunction with the Volkswagen Settlement.

The program will allow system planners to assess the impacts of different electric vehicle types, as well as various electric vehicle charging configurations. In addition to evaluating grid impacts, the pilot program will assess how all utility customers can benefit from increasing adoption of electric transportation through operational cost savings, enabled grid capabilities, improved air quality, and reduced transportation emissions.

## GRID CAPABILITIES ENABLED

- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ INCREASE HOSTING CAPACITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

## MORE ABOUT THE PROGRAM

In 2011, Duke Energy conducted a plug-in electric vehicle charging station pilot in DEC. This pilot provided charging stations and up to $1,000 credit toward installation for customers who bought or leased a plug-in electric vehicle. Duke Energy analyzed the distribution impact and ways to mitigate those impacts as electric vehicles come into its service territory; the technical capabilities that the charging stations can offer to help mitigate those potential impacts; and when, where, how long, and how often a customer charges their electric vehicle.

### Fast Charging Deployment Needed for Market Growth

Electric vehicles are coming to North Carolina as sales growth through the end of 2017 continued with a compound annual growth rate of 62% since 2011. Lack of charging stations is commonly cited as a barrier to purchasing an EV. The program estimates that approximately 1,000 public direct-current fast charging ("DCFC") plugs will be necessary by 2025 to support current forecasts of EV market growth. Currently, there are only 64 open-standard, publicly available DCFC plugs in North Carolina.

### Volkswagen Environmental Mitigation Trust

In 2016, Volkswagen agreed to spend up to $14.7 billion to settle allegations of cheating emissions standards. Of that amount, $2.9 billion was used to establish an Environmental Mitigation Trust, which states and U.S. territories may use to invest in transportation projects that will reduce NOx emissions. Of that amount, $92 million was allocated to North Carolina as a beneficiary under the Settlement Trust. In August 2018, the NCDEQ released the final draft of the state's Beneficiary Mitigation Plan ("BMP"). Eligible mitigation actions under the BMP include replacing or repowering diesel school buses, transit buses, and heavy-duty on-road and off-road vehicles. In addition, beneficiaries may utilize up to 15% of their total allocation on costs relating to light duty, zero-emission vehicle supply equipment.

### Other States Are Embracing Electric Vehicles

The Florida PSC approved an EV Infrastructure Pilot proposed by DEF, including public Level 2 and DC Fast Charging; in New York, ConEdison is supporting the deployment of electric school and transit buses, planned fast charging networks, and residential customer charging research. In Orlando, Florida, the Orlando Utilities Commission has deployed one of the largest municipal EV infrastructure programs in the country. Other examples of states that have embraced EVs in a pilot or otherwise include Maryland, Massachusetts, Oregon, Kentucky, Ohio, and California. Georgia Power has installed 25 public fast charging stations, facilitating EV adoption across the state of Georgia. By installing DC Fast Charging stations in the Carolinas, the ET Pilot would build on neighboring networks and allow EV drivers to seamlessly traverse along the crucial interstate corridors.

# PROGRAM: ELECTRIC TRANSPORTATION

DUKE ENERGY



# PROGRAM: CUSTOMER DATA ACCESS

DUKE ENERGY

**The Customer Data Access program focuses on preparing key data systems for sharing data in a manner that aligns with prevailing data access protocols such as the Green Button standard.**

## DESCRIPTION

Currently, the Company offers a method for customers to download their trailing energy usage data into an XML format. The Customer Data Access program will incorporate modern data access protocols such as the current "**Green Button-Download My Data**" functionality.

"**Green Button-Connect My Data** (CMD)" is a regular automatic transfer of a customer's interval usage data to a third party upon authorization by the customer. The Customer Data Access program will evaluate deployment of CMD or functionality like CMD based on several factors and requirements relevant to North Carolina customers and stakeholders.

## GRID CAPABILITIES ENABLED

- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# **PROGRAM:** CUSTOMER DATA ACCESS

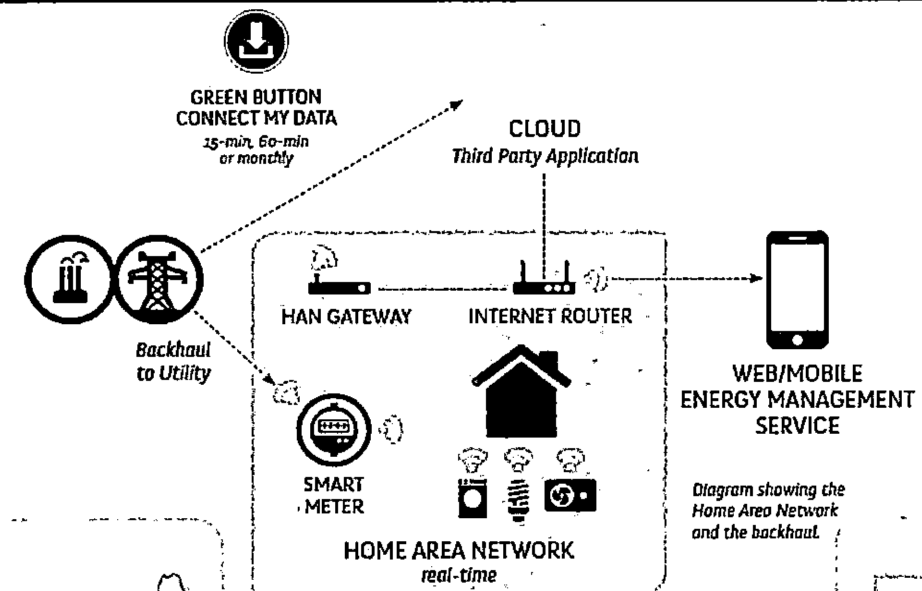
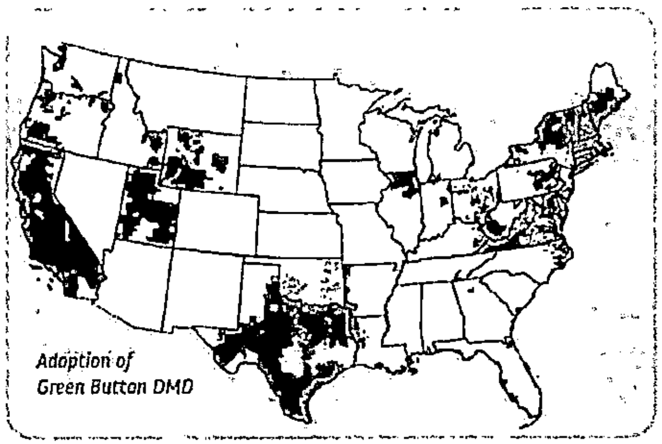
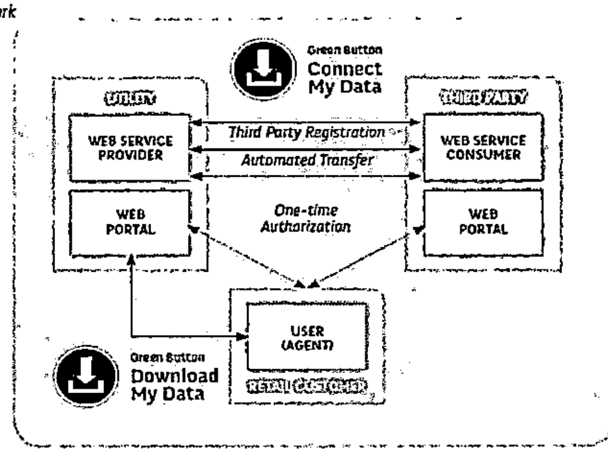



*Diagram showing the Home Area Network and the backhaul*




*Source: Murry, M. and Hawley, J., Got Data? The Value of Energy Data Access to Consumers. More Than Smart. January 2016. <Retrieved from http://www.missiondata.org/s/Got-Data-value-of-energy-data-access-to-consumers.pdf>*

# PROGRAM: TRANSMISSION SYSTEM INTELLIGENCE

DUKE ENERGY.



**The Transmission System Intelligence program deploys transformational system monitoring and control equipment to enable faster response to outages and more intelligent analysis of issues on the grid.**

## DESCRIPTION

Transmission grid automation improvements will reduce the duration and impacts associated with transmission system issues.

Improvements in transmission system device communication capabilities enable better protection and monitoring of system equipment. The data collected from intelligent communication equipment helps better assess and optimize transmission asset health.

The Transmission System Intelligence program includes 1) the **replacement of electromechanical relays** with remotely operated digital relays, 2) the implementation of **intelligence and monitoring technology** capable of providing asset health data and driving predictive maintenance programs, and 3) the deployment of **remote monitoring and control** functionality for substation devices, and rapid service restoration.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: TRANSMISSION SYSTEM INTELLIGENCE

DUKE ENERGY.

## MORE ABOUT THE PROGRAM

### System Intelligence and Monitoring

This subprogram focuses on a machine-learning platform that can determine when equipment maintenance or repair is needed. Health and Risk Monitoring (HRM) of the transmission system allows asset managers to proactively address equipment issues before catastrophic equipment failures occur. The HRM platform utilizes Condition Based Monitoring (CBM) – the continuous remote monitoring of asset health data which is used to extend asset life or execute mitigating activities to prevent equipment failures. HRM supplements CBM data with information from Digital Fault Recorders (DFR), which record the details of transmission system faults to support the types of post-fault event analysis that drives future system performance improvements.

### Electromechanical to Digital Relays

This subprogram replaces noncommunicating electromechanical and solid state relays with digital relays. Modern relay design with communications capabilities and microprocessor technology enables quicker recovery from events than the design of the existing electromechanical relays. One digital relay is capable of replacing a variety of legacy single-function electromechanical relays. Two-way communications and event recording capabilities allow them to provide device performance information following a system event to support continuous system design and operational improvements. Additionally, they identify line fault locations, which is the ability to use device data to calculate the distance down a line to a line fault, rather than manually assessing and patrolling transmission lines.

### Remote Substation Monitoring

This subprogram enables operators to remotely monitor and control substations. This includes the installation or upgrade of supervisory control and data acquisition system (SCADA) interfaces for substation devices, called remote terminal units (RTUs), and upgrades to associated data communication channels. This subprogram is a critical enabler for programs like Integrated Volt/Var Control and Distribution Automation. This subprogram also upgrades serial communication to IP communication for existing RTUs to collect more data and support more devices.

### Remote Control Switches

This subprogram replaces non-communicating switches with modern switches enabled with SCADA communication and remote control capabilities. Transmission line switches are currently manually operated in most substations and cannot be remotely monitored or controlled. Switching, a grid operation often used to section off portions of the transmission system in order to perform equipment maintenance or isolate trouble spots to minimize impacts to customers, has historically required a technician to go to a substation and manually operate one or more line switches. This subprogram increases the number of remote controlled switches to support faster isolation of trouble spots on the transmission system and more rapid restoration following line faults.

# PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY.



**The Transmission (H&R) program works to create a stronger and more resilient transmission grid capable of withstanding or quickly recovering from extreme external events, natural or man-made.**

## DESCRIPTION

Each Transmission H&R sub-program works to address unique challenges in ways that harden the system, and not only minimize impacts to customers, but enhance their electric service experience. The **44-kV System Upgrade** subprogram both protects the 44-kV system from extreme weather, but also paves the way for more DER interconnections by creating additional capacity on the system to transport generation from large scale solar sites. Similarly, the **Targeted Line Rebuild for Extreme Weather** subprogram protects some of the higher voltage transmission lines from extreme weather by addressing vulnerable wooden structures.

The **Networking Radially Served Substations** subprogram builds in more resiliency to the transmission system by creating alternative ways to provide customers with reliable electricity supply in the case of an issue with the primary transmission feed; and, the **Substation Flood Mitigation** subprogram builds in protection for substations most vulnerable to flood damage. Altogether, these H&R efforts not only enhance the functionality of individual assets, but substantially improve the overall functionality of the system, particularly under extreme weather conditions. The long-term plan for hardening and resiliency is to relocate or strengthen at-risk assets or other solutions such as raising the flood plane at that site.

## GRID CAPABILITIES ENABLED

- ✓ IMPROVE RELIABILITY
- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE PHYSICAL SECURITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

# PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY.

## MORE ABOUT THE PROGRAM

### 44kV System Upgrades

Rebuilds and upgrades targeted portions of the 44-kV system to both harden the system against extreme weather, position the system to support DER, and make the overall system more resilient. This will be accomplished in three phases:

- PHASE I (infrastructure upgrades): structurally rebuilds the system, replacing wood structures with taller/stronger steel or concrete structures to better withstand damage in extreme weather conditions. Rebuilding 44-kV lines to 100-kV standards improves performance due to greater elevation and clearance from vegetation. The increased conductor spacing between each of the phases and the addition of basic insulation decreases impacts of lightning events.
- PHASE II (voltage conversions): converts specific circuits of the 44-kV system to 100-kV, making them more capable of supporting large scale solar, storage and other DER. These conversions also require converting the substations served by these lines, which generally involves installing high rated equipment such as transformers and breakers. Portions of the 44-kV system, particularly in rural areas that are prime locations for utility scale solar development, are capacity constrained and unable to support additional interconnections.
- PHASE III (circuit looping): builds in circuit ties between upgraded and converted circuits. This creates a looped circuit design capable of feeding power to these circuits from other sources, as needed, to provide additional system resiliency.

### Networking Radially Served Substations

Increases resiliency of radially served substations where outage duration is higher than average, including: networked lines sectionalized into separate radial lines, and lines designed as radial feeders. Networked radial lines can be re-networked by replacing the conductor with higher ampacity and by upgrading the protective relaying. Lines designed as radial feeders will be networked to existing lines into another substation. Substations served by networked transmission lines can be served from either end of the line and the line can be sectionalized to isolate an interruption and restore the majority, if not all, of customers before the full line is restored.

# PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY.



## MORE ABOUT THE PROGRAM

**Substation Flood Mitigation**

Systematically reviewing and prioritizing substations at risk of flooding to determine the proper mitigation solution, which may include elevating or modifying equipment in substations or relocating substations altogether.

**Targeted Line Rebuilds for Extreme Weather Events**

Specific transmission lines require rebuilding to withstand extreme weather (including wind and ice) and mitigate the risk of unplanned outages. Lines are targeted based on risk-advised decisions along with selection criteria including: tower height, tower condition, and age of asset. Proactive replacement of wooden poles to steel poles that comply with the National Electrical Safety Code (NESC) achieve benefits such as protecting extreme weather and reducing O&M costs.

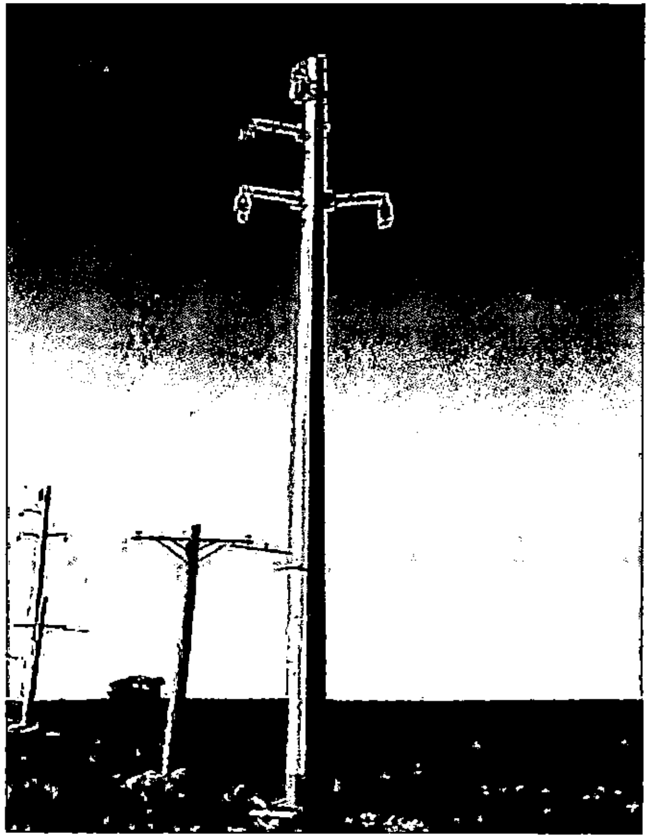
# PROGRAM: TRANSMISSION HARDENING & RESILIENCY (H&R)

DUKE ENERGY.



## TRANSMISSION POLE REPLACEMENTS

69 KV WOOD POLE CONSTRUCTION



NEW 69 KV STEEL POLE CONSTRUCTION

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# PROGRAM: TRANSFORMER BANK REPLACEMENT

DUKE ENERGY.



**The Transformer Bank Replacement program leverages new system intelligence capabilities to target transformers before they fail.**

## DESCRIPTION

Predictive and proactive replacement programs like Transformer Bank Replacement significantly reduce the impacts and costs of replacement when compared to performing the same work following a catastrophic failure.

The objective of this program is to anticipate future transformer failures and replace those transformers in an orderly fashion, avoiding the cost and customer outage minutes associated with these failures. Catastrophic failures often result in significant oil spills, requiring expensive cleanup and other mitigation. Proactive replacement also reduces contingent material inventory needed, since replacements have a 12-24 month manufacturing lead time.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

# PROGRAM: OIL BREAKER REPLACEMENT





**The Oil Breaker Replacement program identifies and replaces oil-filled circuit breakers on the transmission and distribution systems with modern technology.**

## DESCRIPTION

The purpose of this program is to replace these legacy assets with breaker technology capable of two-way communications and remote operations.

Transmission level oil breakers will be replaced with the modern sulfur hexafluoride gas ($SF_6$) circuit breaker technology. The medium voltage distribution level oil-filled breakers will be replaced with modern vacuum circuit breaker technology.

The new communication and control capabilities of this modern technology better positions the transmission and distribution systems to work with grid automation systems to better respond to electric grid events. Looking forward, these fast-response gas and vacuum breakers are better suited for protecting circuits with higher solar and other variable energy resource penetration.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ MODERNIZE GRID OPERATIONS & PLANNING

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**OPTIMIZE** the total customer experience

# PROGRAM: PHYSICAL & CYBER SECURITY

DUKE ENERGY.



**The Physical and Cyber Security program protects against the potential risks and impacts of attacks on the electric grid.**

## DESCRIPTION

The program focuses on hardening above the standard compliance requirements. Transmission elements of the program include:

- **Transmission substation physical security**
- **Windows-based change outs** to address cyber security standards for older Windows-based relays.
- **Cyber security enhancements for non-bulk electric system substations**
- **Electromagnetic Pulse and Intentional Electromagnetic Interference (EMP/IEMI) Protection**

At the distribution system level, much of the focus involves securing and improving risk mitigation of remotely controlled field equipment. An example is enabling door alarms and entry notifications. Programs include:

- **Device Entry Alert System** (DEAS)
- **Distribution Line Device Cyber Protection**
- **Secure Access Device Management** (SADM) - a single tool to remotely and securely perform device management activities and event record retrieval on the entire transmission and distribution device inventory.

## GRID CAPABILITIES ENABLED

- ✓ HARDEN FOR RESILIENCY
- ✓ IMPROVE CYBER SECURITY
- ✓ IMPROVE PHYSICAL SECURITY
- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**PROTECT** to reduce threats to the grid

## MORE ABOUT THE PROGRAM

**Transmission Substation Physical Security**

This subprogram enhances the grid resiliency as part of the overall Transmission Security program. Tier 1 site enhancements include high security perimeter fencing and lighting, intrusion detection technology, new security enclosure buildings, hardening of existing control houses, security cameras, and access control. Tier 2 site enhancements include high security perimeter fencing and lighting.

**Windows-based Unit Change Outs**

The Windows-based Unit Change Outs effort replaces older Windows-based relays that cannot be upgraded due to technology constraints (such as insufficient memory or relay condition). Following these upgrades, the new devices will operate in a Linux environment and be compliant with standards.

**Cyber Security Enhancements for non-BES**

Cyber Security Enhancements for non-bulk electric system (BES) substations implements protective measures against possible cyber-attacks at those non-BES substations that have Internet-Protocol (IP) routable devices. Such measures include the installation of firewalls and the replacement of vulnerable devices.

**EMP/IEMI Protection**

Electromagnetic pulses (EMP) and Intentional Electromagnetic Interference (IEMI) can create disruptions for electronic equipment. The measures taken to protect against them focus on hardening and protecting targeted equipment. The electric industry is engaged in significant research, led by the Electric Power Research Institute (EPRI), focused on improving cost-effective and feasible mitigation against EMP/IEMI. This subprogram will focus on pre-scaled implementation of industry research findings.

## MORE ABOUT THE PROGRAM

**Device Entry Alert System (DEAS)**

The Device Entry Alert System (DEAS) project will install an entry door alarm head-end system and deliver processes to enhance physical and cyber security on the distribution systems' intelligent electronic devices (IEDs). This tool will ensure that all physical access of IEDs and related infrastructure in the field are being tracked and monitored.

**Secure Access and Device Management (SADM)**

SADM provides a tool to remotely and securely perform device management activities and event record retrieval on our entire device inventory in transmission and distribution. The goal of the project is to improve the security of field devices and increase compliance with North American Electric Reliability Corporation critical infrastructure protection (NERC CIP) and other security requirements.

SADM also provides process and labor efficiencies associated with device management, and improves post-event resolution. Within this program, we will standardize systems and processes for secure remote access to field devices, implement device management tasks (including password management, firmware management, configuration management), manage post-fault and other operational event records, and implement a common solution and support model across all jurisdictions within transmission and distribution.

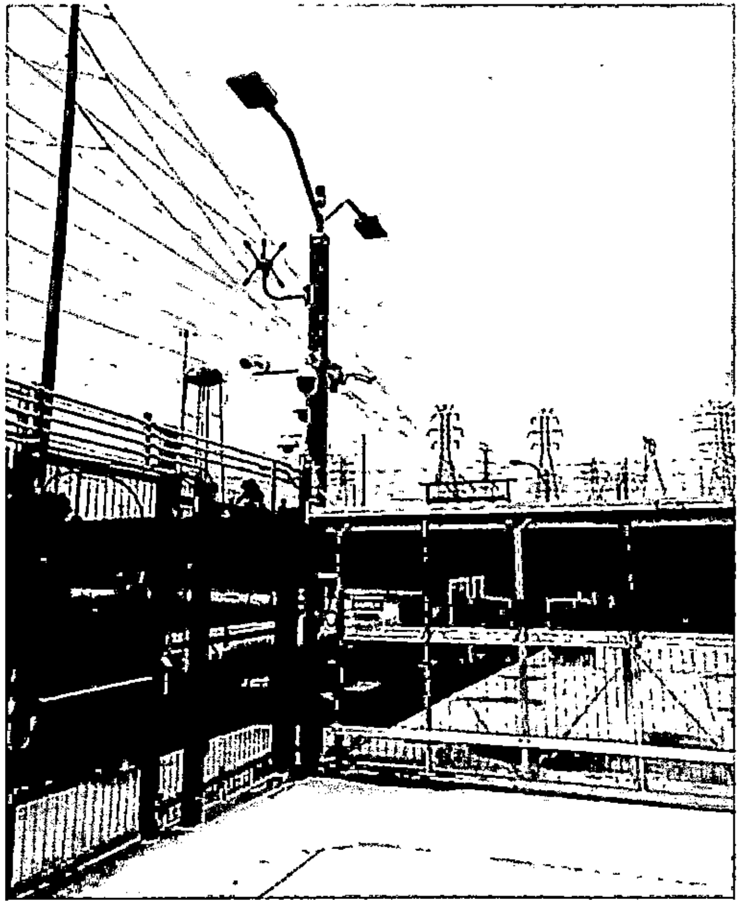
**Distribution Line Device Cyber Protection**

The Distribution Line Device Cyber Protection projects address physical and cyber security risks for thousands of SCADA-controlled line devices (e.g., regulators, capacitors, reclosers, etc.). The focus of the projects in this workstream is targeted replacement of legacy control equipment with Enterprise Security and Advanced Distribution Management System compliant equipment. The newer installed equipment meets or exceeds Duke Energy Industrial Control System (ICS) enterprise security requirements and also provides a platform for future asset management enhancements, such as remote firmware and device settings management, reducing the need to travel physically to a site to perform a system upgrade. Examples of equipment being replaced include capacitor and distribution (recloser) control devices.

# PROGRAM: PHYSICAL & CYBER SECURITY

DUKE ENERGY.

## COCHRANE FENCE & MAIN ENTRANCE CRASH GATE



# PROGRAM: ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

DUKE ENERGY.



**The Enterprise Communications program modernizes and secures the critical communications between intelligent grid management systems, data and controls systems, and sensing and control devices.**

## DESCRIPTION

The program addresses technology obsolesce, secures vulnerabilities, and provides new workforce-enabling capabilities. This program includes improvement and expansion of the entire communications network from the high-speed, high-capacity backbone fiber optic and microwave networks to the wireless connections at the edge of the grid. These upgrades help build the secure communications required for the increasing number of smart components, sensors, and remotely activated devices on the transmission and distribution systems.

Key communication efforts are: (1) **Mission Critical Transport** which strategically upgrades the infrastructure required for high-speed, reliable, sustainable, interoperable communications for grid devices and personnel; (2) **Grid Wide Area Network (Grid WAN)** which improves network reliability, performance and security for current grid management/control applications; (3) **Mission Critical Voice** which replaces current Land Mobile Radio systems with enhanced, reliable, sustainable, interoperable communications across all service territories; and (4) **Next Generation Cellular** which replaces obsolete 2G/3G cellular technology with the more reliable and secure 4G/5G technology required for modern grid devices in the field.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE CYBER SECURITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

## MORE ABOUT THE PROGRAM

### Mission Critical Transport

Implements the strategic advancements to the backbone of the communication network to ensure reliable, sustainable, interoperable communications for grid devices and personnel. Replaces end-of-life fiber cable, optical systems, and microwave systems; strategically expands high-capacity fiber to new, targeted routes; and investigates alternatives for faster or more cost-effective fiber deployments.

### Business Wide Area Network

Updates data network architecture to improve reliability and performance of the core business. Assesses capacity and redundancy requirements and evaluates network options for the core business network and associates area network structures. Supports growing demands for workforce mobility, real-time video capture, data transport needs, and mitigating communication network congestion.

### Grid-wide Area Network (Grid WAN)

Improves network reliability, performance and security for grid control, O&M applications by replacing end-of-life data network hardware and converting substations to an IP network architecture. Employs a network redesign, providing capacity and resiliency, and positioning the network to support Field Area Network (FAN) and Neighborhood Area Network (NAN) needed for enabling a smart cities future.

### Mission Critical Voice

Strategic replacement and improvement of mission-critical voice (radio) communications to provide reliable, sustainable, interoperable communications for all jurisdictions and businesses. The new radio system will provide increased functionality and interoperability between regions, allowing field workers to use the same radio system to help another region during major storms.

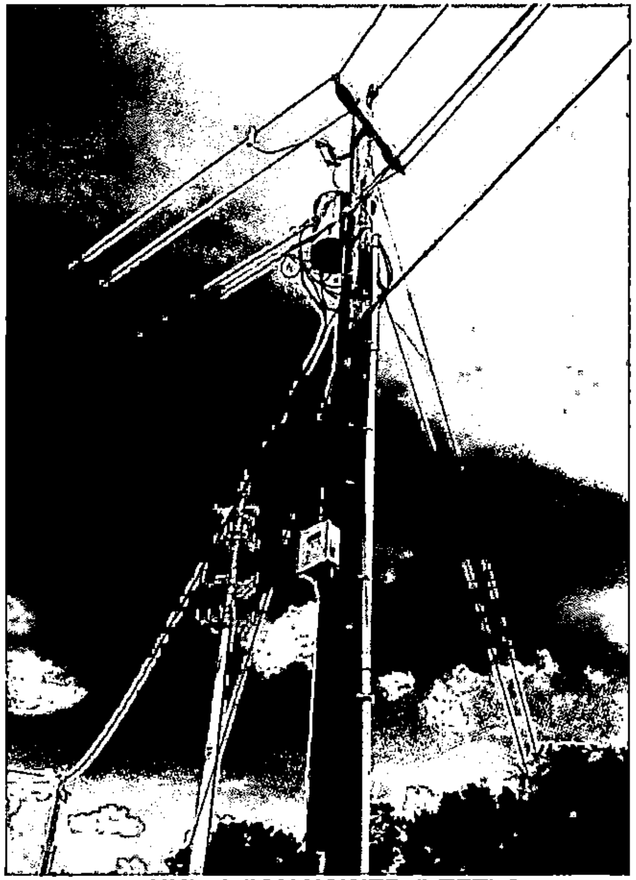
### Next Generation Cellular

Addresses the need to migrate 2G/3G communication networks (to be decommissioned by cellular service providers) to updated 4G/5G. Replaces existing network devices located on distribution line devices. In addition to supporting communication continuity through network decommissioning, these upgrades provide greater network bandwidth, lower data latency, and better cybersecurity protection.

# **PROGRAM:** ENTERPRISE COMMUNICATIONS ADVANCED SYSTEMS

DUKE ENERGY.






**COMMUNICATION TOWER (LEFT) &**
**POLE-MOUNTED COMMUNICATION NODE**

# PROGRAM: ENTERPRISE APPLICATIONS

DUKE ENERGY.



**The Enterprise Applications program deploys the systems and upgrades needed to monitor the health and security of the grid and analyze data to enable grid automation and optimization technologies.**

## DESCRIPTION

Upgrades to existing enterprise applications enable system optimization and overall better system performance. Within the program, there are two main components responsible for the delivery of enterprise technology solutions that support transmission, distribution, and other critical lines of business: (1) **Enterprise Systems** and (2) **Grid Analytics**.

This effort focuses on delivering transformative, cross-functional technical solutions to the enterprise in non-disruptive ways. Elements within the portfolio include the Integrated Tools for Outage Applications (iTOA), which works to drive standardization and coordination of grid control center tools and the Targeted Undergrounding (TUG) System, which facilitates efficient workflows via asset management and mapping system upgrades.

Grid Analytics optimizes the electric system health and performance through the deployment of the Health Risk Management (HRM) tool and Enterprise Distribution System Health (EDSH) tool. These tools help to prevent equipment failures and improve asset performance on the transmission and distribution systems, respectively.

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE AUTOMATION
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ IMPROVE RELIABILITY
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ IMPROVE PHYSICAL SECURITY

## VALUE TO OUR CUSTOMERS

- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

# PROGRAM: ENTERPRISE APPLICATIONS

DUKE ENERGY.



## MORE ABOUT THE PROGRAM

**Integrated Tools for Operations Application (ITOA)**

ITOA is a new platform that optimizes current processes and drives standardization regarding system functionality, work processes, and configuration. This project also upgrades and consolidates outage coordination as well as planned switching and logging applications for transmission and distribution control centers.

**Targeted Undergrounding (TUG) System**

The TUG System automates manual processes and facilitates faster and more efficient workflow by integrating asset management systems. The product enhances the existing enterprise systems for tracking TUG work and creates new mapping capabilities. The mapping enables visualization of the ongoing targeted underground work and consistency in reporting.

**Health and Risk Management (HRM)**

HRM will provide a new platform for collecting data and applying analytics optimization for managing transmission system assets. This sub-program will collect and analyze data to improve the management of assets by using predictive and prescriptive analytics and take proactive steps to prevent or mitigate disruptive events..

**Enterprise Distribution System Health (EDSH)**

EDSH provides a platform that enables PQR&I Planning, Governance, and Customer Delivery to improve reliability and customer satisfaction. It will enable customer-centric reliability planning and provide a basis for optimizing investments using predictive and prescriptive analytics and allow Duke Energy to take proactive steps to prevent or mitigate disruptive events.

## **PROGRAM:** ENTERPRISE APPLICATIONS

# PROGRAM: DER DISPATCH ENTERPRISE TOOL

DUKE ENERGY.

**The DER Dispatch Enterprise Tool is a software-based solution that provides operators with the ability to monitor and manage both transmission and distribution connected DERs.**

## DESCRIPTION

This tool will coordinate with the Distribution Management System (DMS) and Energy Management System (EMS) to improve the way DERs are integrated in the energy supply mix, both at the Distribution and the bulk power level.

By providing system-wide visualization and control of large-scale DERs, the DER Dispatch Tool will enable system operators to model, forecast, and dispatch a portfolio of distributed energy resources, like solar generation, biofuel generation and energy storage, based on system conditions and real-time customer demand. This tool will help meet the need to match energy demand with supply, especially in emergency conditions.

Current processes and tools provide system operators with a rudimentary ability to quickly shed large blocks of solar generation in emergency conditions to meet standards for real power control (BAL-001-2). The proposed solution will provide operators with a more automated and refined toolset to optimize management of both utility and customer owned DERs to meet system stability requirements.

This system will replace an existing tool in DEP that is used to dispatch distribution connected solar in 50 MW increments

## GRID CAPABILITIES ENABLED

- ✓ INCREASE MONITORING & VISIBILITY
- ✓ INCREASE DISTRIBUTED INTELLIGENCE
- ✓ ENABLE VOLTAGE CONTROL
- ✓ ACCOMMODATE TWO-WAY POWER FLOWS
- ✓ EXPAND CUSTOMER OPTIONS AND CONTROL

## VALUE TO OUR CUSTOMERS

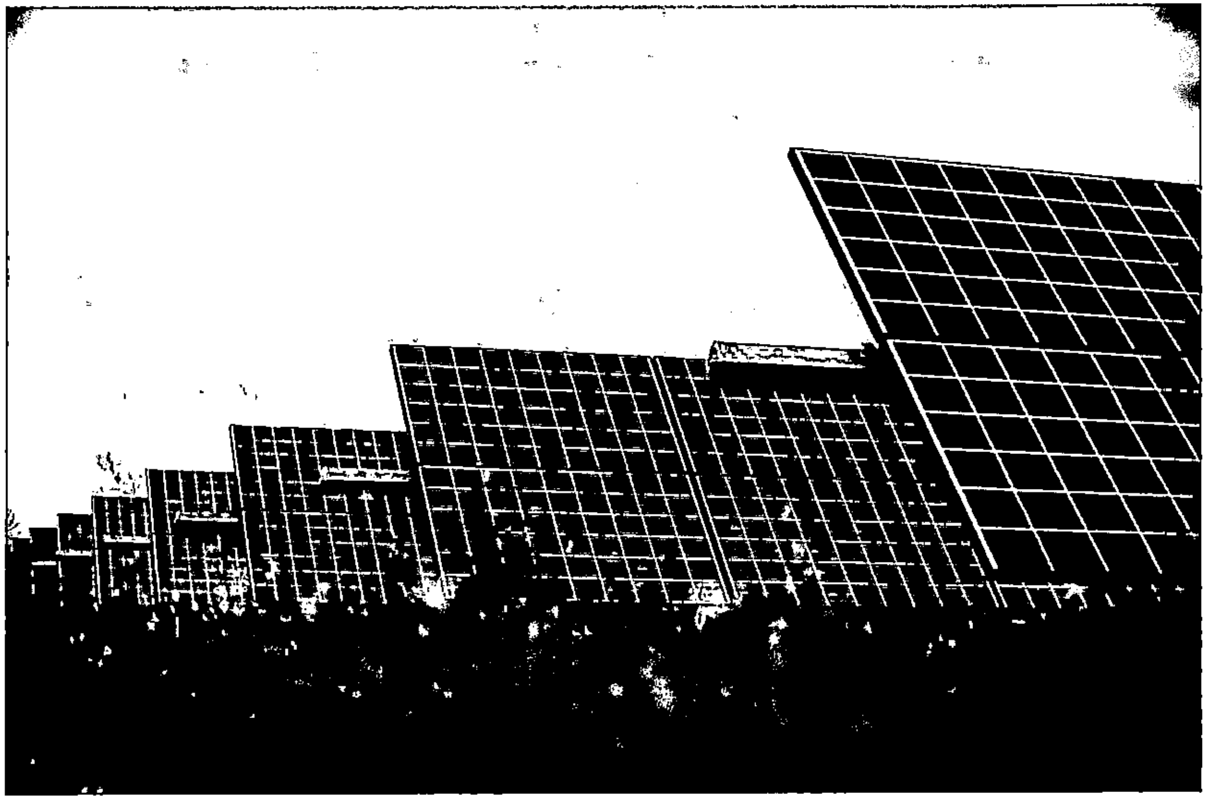
- ✓ MAINTAIN REASONABLE RATES
- ✓ IMPROVE RELIABILITY, SAFETY, RESILIENCY
- ✓ MEET OR EXCEED CUSTOMER EXPECTATIONS

## WHERE IT FITS IN OUR PLAN

**MODERNIZE** by leveraging enterprise systems and technology advancements

DUKE ENERGY.





DUKE ENERGY.

NORTH CAROLINA GRID IMPROVEMENT PLAN

# PORTFOLIO SUMMARY

## FOR STAKEHOLDER WORKSHOP

11/08/18

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# NC GRID IMPROVEMENT PLAN PORTFOLIO SUMMARY

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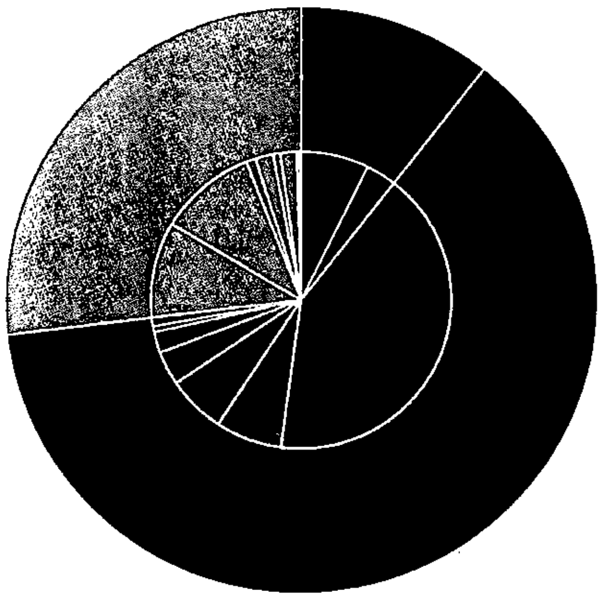

| Program | 3 Year Range |
|---|---|
| **Compliance: Cost Effectiveness Justified** | **$164 - 266M** |
| Physical Security | $113 - 184M |
| Cyber Security | $51 - 83M |
| **Cost Benefit & Cost Effectiveness Justified** | **$973 - 1580M** |
| SOG | $412 - 670M |
| Distribution H&R | $111 - 180M |
| IVVC DEC | $123 - 200M |
| Transmission H&R | $98 - 159M |
| TUG | $57 - 93M |
| Energy Storage | $103 - 167M |
| Transmission Bank Replacement | $36 - 58M |
| D-OIL Breaker Replacements | $10 - 15M |
| T-OIL Breaker Replacements | $15 - 24M |
| DSDR peak shaving to CVR in DEP | $8 - 13M |
| **Rapid Technology Advancement: Cost-Effectiveness Justified** | **$418 - 680M** |
| T&D Communications | $163 - 264M |
| Distribution System Automation | $92 - 150M |
| Transmission System Automtation | $71 - 115M |
| T&D Enterprise Systems | $16 - 26M |
| ISOP | $30 - 48M |
| DER Dispatch Tool | $12 - 20M |
| Electric Vehicle Charging | $27 - 45M |
| Power Electronics for volt/var control | $6 - 10M |
| Customer Data Access | $2 - 3M |
| **Total** | **$1,600 - 2,500M** |

- Cost-Benefit and Cost-Effectiveness Justified (Optimize)

Programs and projects in this category provide customers more net benefits than net costs and solve for one or more external "megatrends."

- Rapid Technology Advancement-Cost Effectiveness Justified (Modernize)

Equipment, software, hardware, operating systems, and/or accepted system operating practice has advanced at an atypical pace in this category causing the need for rapid and sometimes frequent changes within the utility at a system deployment level. Work in this category is usually related to system communication, automation, and intelligence and must be executed at a deliberate pace while ensuring not to deploy new technology before it has reached operational and price point maturity. While not technically compliance work, work in this category is essential for modern system operations.

- Compliance-Cost Effectiveness Justified (Protect)

i. An external law, rule, or regulation applicable to the company requires the work;
ii. A binding legal obligation such as a contract, agency order, or other legal document compels the work; or
iii. The Operations Counsel has approved the work as being critical and imperative to the Company's operations.

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NORTH CAROLINA GRID IMPROVEMENT PLAN

# APPENDIX

## FOR STAKEHOLDER WORKSHOP

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# NORTH CAROLINA GRID IMPROVEMENT PLAN

DUKE ENERGY.



## Megatrends

- Concentrated Growth
- Technology Advancements
- Grid Modernization
- Customer Expectations
- Environmental Commitments
- Impact of Weather Events
- Threats to Grid Infrastructure

## Implications

- Increased Cost
- Decreased Reliability
- Inability to Interconnect DER
- Decreased Customer Satisfaction
- Decreased Economic Attractiveness for North Carolina
- Decreased Demographic Fairness

## Grid Capabilities

- Increase monitoring and visibility
- Increase automation
- Increase distributed intelligence
- Improve reliability
- Harden for resiliency
- Enable voltage control
- Accommodate two-way power flows
- Modernize grid operations
- Improve cyber security
- Improve physical security
- Expand customer options and capabilities
- Increase hosting capacity

## Plan

- Protect
- Modernize
- Optimize

## Programs

- IVVC
- SOG
- TUG
- Power Electronics
- Energy Storage
- Distribution Automation
- Transformer Retrofit
- LDI/HI
- EV Charging
- ISOP
- Customer Data Access
- Transmission System Intelligence
- Transmission H&R
- Transformer Bank Replacement
- Physical & Cyber Security
- Oil Breaker Replacement
- Enterprise Communications Improvement
- Enterprise Apps
- DER Dispatch Tool
- Advanced Metering
- Distribution H&R

## Value to Customers

- Maintain reasonable rates
- Improve reliability, safety, resiliency
- Meet or exceed customer expectations