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October 1, 2018

VIA ELECTRONIC FILING

M. Lynn Jarvis
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: 2018 Smart Grid Technology Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC
Docket No. E-100, Sub 157

Dear Ms. Jarvis:

Pursuant to Commission Rule R8-60.1, I enclose the 2018 Smart Grid Technology Plans of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC for filing in connection with the referenced matter.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

Enclosures

cc: Parties of Record

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Carolinas, LLC and Duke Energy Progress, LLC's 2018 Smart Grid Technology Plans, in Docket No. E-100, Sub 157, have been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

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This the 1st day of October, 2018.

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Duke Energy Carolinas

2018 Smart Grid Technology Plan

DUKE ENERGY.® CAROLINAS

Table of Contents

Overview

As required by the North Carolina Utilities Commission (NCUC) Rule R8-60.1(b), Duke Energy Carolinas (DEC or Company) submits its 2018 Smart Grid Technology Plan (SGTP or Plan). The 2018 Plan represents the smart grid technologies being evaluated, designed, or implemented, and is the best projection of how the Company is making smart grid investments in the near term and leveraging emerging technologies for the future.

Duke Energy has many smart grid technology projects currently underway, and many more technologies and initiatives that are being evaluated for the future.

1. Smart Grid Technology Strategy

Reference	Requirement
R8-60.1 (c) 1	*A summary of the utility's strategy for evaluating and developing smart grid technologies.*

Building a smarter grid for North Carolina

Technology is transforming North Carolina, and changing the way customers use electricity and interact with their electric provider. Reliability remains essential as an increasingly connected population continues to expand, especially in urban areas of the state. Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business – even at a time when that reliability is challenged by the increasing frequency of severe weather events and the very real threat of physical and cyber attack.

The century-old model of one-way power flow from power plant to customer is evolving to one of distributed resources, and customers are increasingly connecting to innovative technologies like private solar, battery storage, electric vehicles and microgrids. Power lines that were once the last mile of a constant and consistently flowing electric grid are now the first stop for a network of thousands of generation sources, pushing a dynamic flow of energy onto an energy highway that was never engineered for multi-directional flow.

Customers today want a new experience – a better experience - built upon information about how they personally use energy and tools to harness that energy and power their lives. And they want a power grid that can adapt to meet their changing energy needs, repair itself faster when there are problems and serve as the backbone of their lives and of the state's digital economy.

The reality is that today's grid, while well maintained, is simply not engineered to handle the changing demands it is being asked to serve. To deliver on customer expectations, we must do more than maintain the power grid; we must transform it, leveraging technology to modernize its operation, making it more reliable, smart and secure.

This means converting the grid from a radial one-way design to a two-way distribution system that can automatically route power from where it is produced, regardless of where that happens on the system, to where it is needed. Duke Energy has made excellent use of the existing grid system, but it and other utilities throughout the nation, must address issues such as DER challenges, physical and cyber security, increased convective weather events and increased customer reliance and expectations since the grid was initially built.

Grid Improvements

The Power/Forward Carolinas grid improvement initiative was developed to transform the state's electric grid, making it more reliable, while also making it smarter and more secure. The initiative is built around these core benefit areas:

- Improve reliability to avoid outages and speed restoration
- Harden the grid against physical and cyber impacts
- Expand solar and distributed technologies across a two-way, smart-thinking grid
- Give customers more options and control over energy use and tools to save money

Improve reliability

Initiatives in this category focus on all points of the grid, with some engineered to reduce the number of outages experienced on the system and others speeding restoration and improving resiliency when an outage occurs. Projects in this category include work to underground the most outage-prone lines on the distribution system, equipment upgrades on both the distribution and transmission system and an advanced smart meter network to improve outage detection and restoration response.

Foundational to improving reliability is a smart-thinking grid that can quickly identify and isolate outages when they occur, and automatically reroute power to speed restoration to customers. This self-optimizing system relies on an advanced network of monitoring and switching technology, as well as upgrades to power lines and other equipment. In some areas where redundant circuits are not available, battery storage and microgrid technology will be employed to restore service to customers while repairs are made.

Smart-thinking grid technology can reduce the number of customers affected by an extended outage by as much as 75 percent. If outages do occur on a smart-thinking grid, power is typically rerouted in less than a minute.

Harden the grid

The threat of severe weather, and physical and cyber attack are real and are among the greatest challenges that utilities face in an increasingly connected, digital world. Requirements to protect the grid and the risk of intrusion are orders of magnitude greater than what they were in the past. As one of the largest utilities in the nation, Duke Energy is a top target of cyberattacks.

Hardening improvements include equipment upgrades on the distribution and transmission system, flood mitigation, animal mitigation, system health tools, physical barriers and access control, and advanced communication and monitoring technologies.

When disruptions do occur, Duke Energy's grid and support systems must be engineered to recover quickly. Resilient energy systems must be designed to survive physical and cyber incidents while sustaining critical functions. Resiliency upgrades include system intelligence and self-healing capabilities through the company's smart-thinking grid deployment, as well as an expanded suite of defensive measures to keep pace with the new world of physical and cyber threats the company faces.

Expand solar and distributed technologies
In addition to improving reliability and resiliency after an outage, the smart-thinking grid will also support the two-way power flows needed to support more innovative technologies like rooftop solar, battery storage, electric vehicles and microgrids. The company is also expanding the use of renewables as part of the work to improve reliability, by using large-scale battery storage systems often powered by solar energy at points across the grid.

Give customers more options and control
When it comes to saving energy and money, information is power. And Duke Energy wants to provide customers with the intelligent information needed to make smart energy choices to conserve and lower their monthly bills. Smart meters are the foundation that helps provide customers detailed data about their energy use – including hourly, daily and average usage – showing them how much energy they are using and when. Having this information available on a daily basis can help customers make informed energy decisions to save money before their bill arrives.

Smart meters are also the gateway to more customer options and control, enabling options like usage alerts, improved outage detection and new programs tailored to help customers make smarter energy choices and take advantage of new technologies.

Driven by data
Duke Energy's grid improvement initiative is built on millions of data points that help target improvements to maximize customer benefits. By targeting investments, we can also keep costs lower for customers while preparing the grid for new technologies that will benefit communities, the environment and our state.

Data is also the foundation of the smart-thinking grid – a system that is more secure against physical and cyber attacks and that anticipates outages and intelligently reroutes power when an outage occurs – keeping service reliable and the power on when customers need it most. Data is also driving the optimization of the grid that will enable Duke Energy to deliver power more efficiently, and support the two-way flow of electricity necessary to grow renewable and emerging technologies like rooftop solar, battery storage, electric vehicles and microgrids.

Smart grid technologies

Certain programs included in the Power/Forward Carolinas grid improvement initiative are technologies that fall under the definition of "smart grid technologies" outlined in Commission Rule R8- 60.1(c), while others are not. All of the programs have similar objectives in the long term, improving reliability and resiliency of the grid; however, certain programs, like Targeted Undergrounding, are not deemed smart grid technologies rule by definition. The Company has determined that smart-thinking, self-optimizing grid technologies, as well as certain transmission improvements, physical and cyber security upgrades, and the advanced monitoring and communication capabilities required to enable a smart grid, meet the criteria for the SGTP and will be outlined within the Plans each year as applicable.

Responsive to customers and stakeholders

For grid improvements to be most effective, they must serve the needs of customers. And Duke Energy is working hard to seek out input and better understand the energy needs of customers as it works to build an effective, but flexible modernization strategy for the state.

Through the North Carolina Public Benefits Funds, administered by Advanced Energy and Duke Energy, along with generous technical support from North Carolina's Electric Membership Cooperatives, Duke Energy and Dominion Energy North Carolina, there have been several smart grid stakeholder education initiatives.

As described in the 2016 Smart Grid Technology Plan, Advanced Energy's outreach efforts are being designed to help our state's residents make well-informed energy decisions. They want to share information about new technologies and services when they believe they can offer value, and they also want to share any concerns that may present risk. Highlights of the accomplishments over the past year include:

Collaborative Initiatives

- Duke Energy continued support of multi-year smart grid education and outreach project through the North Carolina Public Benefits Funds, administered by Advanced Energy and Duke Energy, along with generous technical support from North Carolina's Electric Membership Cooperatives, Duke Energy and Dominion Energy North Carolina.

  The goals and objectives of the project are:
  1. To build awareness among key decision makers on relevant smart grid topics and efforts on technology, economic development, and policy across North Carolina.
  2. To educate key decision makers on cross-sector aspects of grid modernization so that they may inform their communities.
  3. To create interesting and informative educational opportunities that brings grid modernization to light in real life situations in communities.
- In 2017, www.NCSmartGrid.org was created as a repository for educational materials and resources developed as part of the body of work. A webinar series was started in 2017 and has continued in 2018 focused on relevant smart grid technology topics. This series provides non-

technical government and business stakeholders with a convenient and economical option to learn how smart grid is changing North Carolina's future.

- The tables below depict the interest and participation in these educational resources.

Smart Grid Webinar Series	Attendance
Interconnecting Smart Grid and Economic Development	Scheduled for: October 4, 2018
Grid Resiliency - June 6, 2018	54
Energy Storage - April 26, 2018	63
Self-Optimizing Grid Technologies - October 24, 2017	8
Microgrids and Grid Resiliency - September 20, 2017	15
Smart Meters and AMI - June 22, 2017	39
Solar Power and Grid Integration - May 24, 2017	28
Smart Grid Basics - April 26, 2017	36

	Webinar Recording Plays		
NCSmartGrid.org Activity Log	2017	2018 YTD	Cumulative
Grid Resiliency		27	27
Energy Storage		60	60
Self-Optimizing Grid Technologies	10	25	35
Microgrids and Grid Resiliency	23	24	47
Smart Meters and AMI	51	77	128
Solar Power and Grid Integration	108	30	138
Smart Grid Basics	58	24	82

	Website Page Views		
NCSmartGrid.org Activity Log	2017	2018 YTD	Cumulative
Exploring NC Smart Grid Webpage views	772	484	1256
AMI Case Study Article views	120	100	220
Brunswick AMI Case Study Video - plays	65	27	92
Microgrid Case Study Article - views	94	191	285
Battery Storage Case Study Article - views		162	162
Grid Reliability and Resiliency Article - views		91	91

<u>Duke Energy Initiatives</u>

- Duke Energy facilitated several meetings with NCSEA, Public Staff and other interested parties to discuss guidelines regarding third-party access to customer usage data. On June 21, 2018 Duke Energy filed a report with the Commission in Docket No. E-100, Sub 147 regarding areas of agreement and explanations for points on which agreement was not reached. The results of these discussions are provided in Exhibit 2 – Commission Rules on Third Party Access to Customer Usage Data
- In the settlement agreement approved by the North Carolina Utilities Commission (NCUC) on February 23, 2018, in Docket No. E-2, Sub 1142 for the Duke Energy Progress (DEP) rate case, Duke Energy agreed to "host a technical workshop during the second quarter of 2018 regarding the Company's NC Power/Forward grid investments to explain the need for and ongoing benefits of grid investments, and to hear feedback from stakeholders in attendance". The workshop was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute (RMI) convened 65 participants (inclusive of Duke Energy and RMI staff) for a day-long workshop that included content presentations, structured feedback sessions, and facilitated small group breakout sessions. On June 26, the final report for the workshop was filed with the NCUC Docket Nos. E-2, Sub 1142 and E-7, Sub 1146. Duke Energy intends to continue engaging stakeholders to gather input about grid improvement initiatives. The next meeting is planned for Q4, 2018.

2. Improving Reliability and Security of the Grid

Reference	Requirement
R8-60.1 (c) 2	*A description of how the proposed smart grid technology plan will improve reliability and security of the grid.*

Our grid is responding to an increasing number of DER interconnections and storms at a time when reliability is more essential to customers and the economy than ever before. Wind and ice storms are two of the leading causes of outage conditions for our power systems, and flooding has also become an increasing concern. Combined with this, the threat of cyber and physical attacks on the grid are real, and of increasing concern.

- On March 15, 2018 the US Department of Homeland Security (DHS) issued a security alert naming Russia as being responsible for attacks on American critical infrastructure. In July, a briefing was held by the DHS indicating hackers exploited relationships between utilities and their private vendors to steal credentials and gain access to the utility networks.
- On April 2, 2018 S&P Global reported that Energy Transfer Partners LP experienced a cyberattack caused an outage in a third-party company's electronic transaction data for its major natural gas pipeline systems, but pipeline operations were unaffected.
- S&P Global reported that Eversource Energy notified customers it experienced a cyberattack in April. The attack also affected Duke Energy and several other utilities. It took down the electronic transaction data interchanges of at least five natural gas pipeline companies.

A growing risk to the system involves the fact that there are cellular modem (telecom transport) devices installed in many of the line devices (Intelligent Line Devices) in the field, which could increase a potential risk to have a bad actor to reach back to our systems through access through the telecom transport device.

For all the new technology projects listed in the Smart Grid Technology Plan under Section 3 through 5, the benefits described, outline the specific impact each project will have on the reliability and security of the grid. Additionally, the investments as a whole will provide synergies resulting in greater overall value in improving grid security, reliability and resiliency, while also creating greater efficiencies and improving safety and sustainability.

3. Current & Scheduled Technology Deployments

Reference	Requirement
R8-60.1 (c) 3	*For all smart grid technologies currently being deployed or scheduled for implementation within the next five years: (i) – (vii)*

Physical and Cyber Security

Distribution line device uplift (CBC, Regular Controls, MVS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Recloser controls

Duke Energy will be replacing a population of roughly 300 distribution control devices (DCD) that have reached end of life and are not compatible with Duke Energy's ADMS system control use cases nor meet the physical and cyber security requirements for line devices. The current control devices have multiple entry doors that reduce their ability to be secured and lack alarms. One of the primary use cases for Duke's ADMS and Self-Healing capability is the ability to change operating modes of the remote DCD dynamically as automatic switching takes place in the most effective manner to minimize customer impact and maximize equipment reliability, while in the alternate switch state. The legacy DCD devices, when issued a remote operating mode change request by the central control system, shut down the power to their remote communications capability for an extended intermediate period as they cycle to the new mode. During the shutdown period the central control system does not have visibility into the DCD which may lengthen the period before the system can restore power to the unaffected customers automatically. The goal of this replacement is to benefit Duke Energy's customers by installing equipment that is compatible with the ADMS control system and physical security use cases and will enhance the ability of the control system to deliver a more reliable power experience to our customers during automatic switching events.

(ii) The status and timeframe for completion.

The work will start in 2019 and be completed by the end of 2021.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The anticipated book and salvage values of this equipment at time of retirement will be $0, and there is no alternative use for this equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

N/A

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

N/A

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Recloser controls	0.000	0.000	0.000	1.890	1.650	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Benefits include improved reliability of the distribution system; ability to switch between setting profiles to support system reliability; and securing assets from physical inadvertent access.

Secure Access & Device Mgmt. (SADM)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Secure Access and Device Management (SADM) aims to provide a single tool to remotely and securely perform device management activities and event record retrieval on our entire device inventory in transmission and distribution. The project goals are to: Improve the security of devices and increase compliance with NERC CIP and other security requirements, provide process and labor efficiencies associated with device management, and improve post-event resolution.

(ii) The status and timeframe for completion.

The design completion target date is October 2018. Initial infrastructure buildout target date is Q1 2019 and commission complete target date is Q1 2020.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The SADM solution will allow sun setting and decommissioning of locally-purchased solutions in both distribution and transmission. The functionality of the new tool will be new and will replace the need for the existing processes and tools.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

SADM supports internal operations and does not have a customer interface.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

N/A

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
SADM	0.000	0.000	0.301	3.277	0.558	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The goal was to have a single enterprise-wide solution eliminates the need for disparate systems and processes in lieu of a single standard. The project team gathered requirements, determined to purchase instead of internally develop, conducted the RFP processes with multiple vendors, and made selection.

Self-Optimizing Grid

Self-Optimizing Grid (SOG)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Self-Optimizing Grid (SOG) Program implements additional design criteria on distribution circuits that improve reliability and enhances system resiliency. This resiliency will enable the system to reduce outage duration from fault events. Key components of the projects will involve adding capacity to distribution circuits and substations and connecting radial distribution circuits together with automated switches. The head-end enterprise systems such as the self-healing software and the Distribution Management System (DMS) software are essential to enabling this capability.

The SOG is an advancement from “Self-Healing Networks.” The Self-Healing Networks and Feeder Segmentation projects were a foundational step in the progression towards the SOG program. Instead of having individual circuit pairs that can back each other up, the integrated grid network will allow for multiple circuit rerouting options to re-energize segments and minimize customer outage events. The SOG program will further segment the circuits to minimize the number of customers affected by sustained outages and ensures the necessary capacity and connectivity to fully leverage the segmentation.

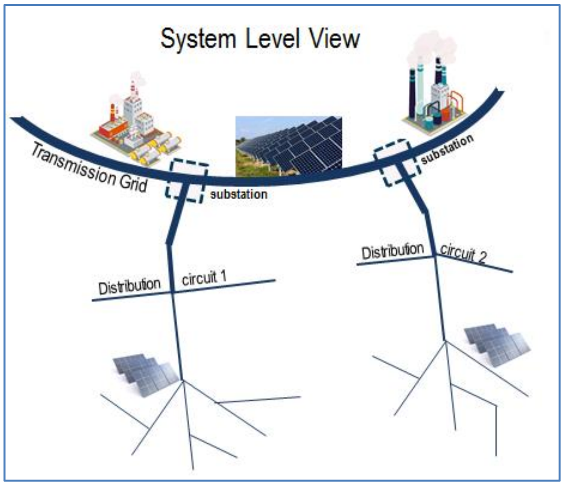
Under this program, circuits will have automated switches deployed according to the SOG guidelines, which outline automated switches approximately every 400 customers, or 3 miles in circuit segment length, or 2 MW peak load. The goal of the SOG program is to have 80% of customers served from circuits that have alternate power re-routing options and sufficient capacity to re-route power without being overloaded the majority of the time. Circuits that meet these additional guidelines will have SOG capabilities.

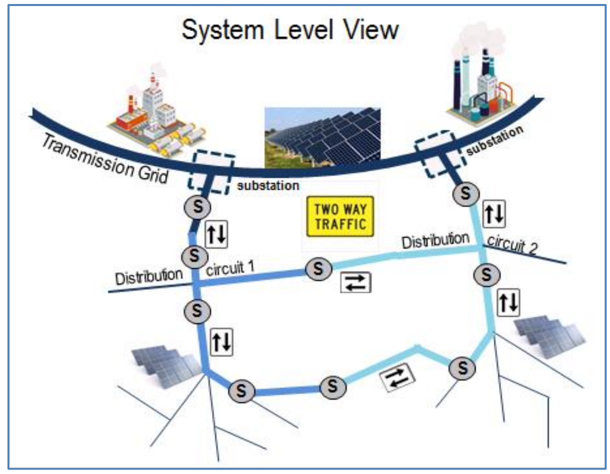
The SOG will automatically reroute power around a problem area, like an outage caused by a tree falling across a line, animal interference, or other fault events. With this automation, the grid can self-identify problems and isolate affected areas by reconfiguring the circuits, which can shorten or even eliminate outages for many customers.

Additionally, these same Self-Optimizing Grid investments and resulting capabilities help the grid to efficiently integrate DER assets (such as roof-top solar) more effectively and efficiently.

- The circuit capacity investments allow for two-way power flow, so that locally-produced DER power can be consumed upstream on adjacent segments within the same circuit
- When that is insufficient, the circuit ties and automation allow the circuit to dynamically reconfigure and allow the DER power to be routed and consumed by adjacent distribution segments and neighborhoods from other nearby circuits

This maximizes the value of DERs and locally-produced power by reducing line losses from transporting that power long distances. SOG’s dynamic re-configuration capability routes locally-produced solar to be consumed locally.





Illustrative view of distribution circuits before SOG **Illustrative view of same circuits after SOG**

(ii) The status and timeframe for completion.

The initial engineering, scoping and planning for the SOG program began in 2017, and field work began in 2018. The 2018 planning will address work plans for 2020, and the planning for following years will occur as part of the annual planning process. 2018 is the first year of the expected multi-year program to achieve the anticipated goal of 80% of customers being served by the SOG.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

During field work, installations will primarily consist of new equipment to achieve the new SOG guidelines. However, there will be instances where aged, automated switches, or other non-automated equipment will need to be replaced. Automated switch equipment typically has an approximate 20-year expected life, and control and communications equipment, an approximate 5 to 7-year expected life.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable as this technology does not transfer information to/from customers.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this technology does not transfer information to/from customers and will not be utilized by third-parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
Automation	4.127	3.404	1.550	37.616	50.102	50.001	70.440
Capacity & Connectivity	14.290	33.798	12.632	45.231	67.624	68.409	93.304

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Self-Optimizing Grid analysis uses the design criteria of segmenting the circuits for approximately 400 customers, 3 miles of circuit, or 2MW of load. Benefits can include:

- Reduces system-wide customers interrupted (CI) and customer minutes of interruption (CMI)
- Creates a networked energy system that improves operational situational awareness
- Minimizes the number of customers impacted by an outage
- Isolates problem areas for quicker mobilization and repair
- Shortens outage duration for impacted customers
- Automates system reconfigurations reducing the need for manual switching
- Improves grid resiliency and ability to recover from major events
- Enables the grid to effectively manage private distributed energy resources

As next generation technologies for switching, protection and controls are identified and vetted via proof of concept testing and business case validation, they will be incorporated into the SOG planning process. Device evaluation will be based on opportunity for enhanced grid capability, increased grid security, or decreased cost.

Advanced Distribution Management System (ADMS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The DMS Consolidation Program is a comprehensive, enterprise-wide program to deploy a common Distribution Management System (DMS) across Duke Energy. Consolidating to a single vendor platform for the DMS and SCADA systems enables operational consistency and efficiency, integrates future solutions, and leverages multiple support teams throughout the enterprise. There are currently three active projects in the DMS Program.

The SCADA Project will upgrade SCADA version 3.1 across Duke Energy. In North Carolina specifically, the DEC service area currently uses the common SCADA version 2.6, and this project will upgrade the SCADA system to version 3.1.

The DMS Project will upgrade the common DMS version 3.9 across Duke Energy. In North Carolina specifically, the DEC service area currently uses the DMS version 3.5, so this project will upgrade the DMS to version 3.9.

The CL FLISR Pre-Scale Project is initially a small-scale utilization of the closed loop fault location isolation and service restoration (CL FLISR) functionality within the common DMS on 26 circuits and 7 substations in a targeted operating area of DEC. This functionality will detect and locate faults, then calculate and enact an electrically valid switching solution that isolates the fault and minimizes the area impacted by the resulting outage. This pre-scale deployment will enable Duke Energy to test and fully understand the functionality and evaluate the benefits of deploying this CL FLISR functionality system-wide. We are continuing to pilot this functionality so that we have additional opportunities for it to operate.

The ADMS (OMS) Project will install the ADMS Outage Management functions cross Duke Energy to a common version 3.9. In North Carolina specifically, this will allow the operators to leverage one geographic view for managing the grid and outages. Implementing a common platform across all service territories will support standardized operations. This will allow more rapid response during high impact events by reducing learning curve for shared resources. In addition, a consolidated DMS and OMS reduces system complexity and cost to maintain.

(ii) The status and timeframe for completion.

	2015	2016	2017	2018	2019	2020	2021
DMS 3.7	Start Date					Close Date	
DEC	Q4					Q1	
		Start Date				Close Date	
DEP		Q1				Q1	
SCADA 3.1				Start Date		Close Date	
DEC				Q3		Q1	
		Start Date				Close Date	
DEP		Q3				Q1	
CL FLISR	Start Date						
DEC Pre-scale	Q4				Q2		
ADMS				Start Date			Close Date
DEC				Q1			Q4
				Start Date			Close Date
DEP				Q1			Q4

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The DMS and SCADA conversion will replace existing computer hardware. The replaced hardware (servers and server support equipment) will be repurposed and reused within the company for other projects.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable as this project does not involve the transfer of customer information.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not involve the transfer of customer information.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

ADMS Consolidation Program Costs

$ in millions	Actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
SCADA	0.259	0.913	0.949	0.960	2.474	1.664	0.000	0.000
DMS (3.5)	6.663	2.858	0.638	0.857	1.886	1.270	0.000	0.000
CL FLISR	1.207	0.484	0.682	1.270	1.035	2.282	5.094	3.358
OMS (ADMS)	0.578	7.012	4.278	5.633	8.518	9.742	11.603	7.571
Total	8.706	11.266	6.547	8.721	8.706	11.266	6.547	8.721

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The DMS Consolidation Program supports the overall vision of Duke Energy to move to a single vendor platform for DMS and SCADA by scaling common platforms to all locations in one coordinated program.

Enterprise wide, quantifiable benefits expected from the DMS consolidation are approximately $4M annually once the system is fully deployed. These savings are primarily driven by the elimination of costs associated with annual vendor support and maintenance contracts, upgrades, and issue resolution costs for multiple control system vendors, as well as an anticipated reduction in internal maintenance and support required for multiple control system vendors. Some of the additional, non-quantifiable benefits include:

- Improved reliability of the distribution system
- Near real time (every 15 minutes or by exception) power flow calculations of the entire distribution network
- Fault location, isolation, and service restoration
- Switching plan formulation, validation, and execution
- Linkage to the Energy Management System on the state of the distribution network
- Functionality to meet peak shaving requirements through DEP EE/DSM programs
- Platform for integration of distributed renewable power sources within the distribution grid
- Remote Distribution Control Center (DCC) monitoring and control of station and field devices
- Alarming capability to issue alarms based on operational conditions to notify DCC operators of changes in system or device conditions
- Capability to electronically tag field devices for safety and informational purposes
- Substation graphical dashboard monitoring and control capabilities
- Emergency load shed functionality including surgical load shed capability
- Framework to standardize processes and operations across the enterprise
- Trend and forecast visualization
- Cold load pickup improvements, reducing outage time

Distribution System Modernization, Automation and Intelligence

Urban Underground System Automation

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

An urban underground automation system is installed in locations where reliability can have a direct impact on safety, such as a downtown or dense multi-use location, or other places with high profile loads like airports, stadiums, etc. This technology responds to a loss of power by utilizing real-time data to isolate faults and reconfigure local distribution networks to minimize customer outages.

There are many benefits to an underground distribution automation system, including:

- Reducing the number of outages and improving the customers' experience
- Reducing the duration of outages

- Restoring power in 45 seconds or less in most cases
- Continuously assessing the state of the grid for potential issues

Duke Energy has made investments in various auto-throw over sectionalizing and isolation switchgear in the DEC jurisdiction. There is a large amount of this equipment located in the Uptown Charlotte area in underground vaults. This gear has been locally operated by crew members entering enclosed spaces, requiring the crew member to open a control panel and live-front style switch cabinet to operate the gear. From an asset maintenance perspective, if a relay or battery failure occurs, the only way that the Company would know that this event had occurred would be as the result of a customer outage related to equipment failure or annual maintenance inspections. The goal of the Charlotte Automation & Integration (A&I) proof of concept is to place new communication and logic settings in the relays, create DMS control and alarm monitoring screens, install communications gear, and commission and check out the control and equipment to allow for Grid Management/Distribution Control Center to remotely monitor and control the switchgear. This will allow for switchgear to be operated remotely, promote system awareness of fault and other system event locations, allow crew members to not be in the proximity of the gear while it is being operated, and enhance system asset maintenance.

(ii) The status and timeframe for completion.

To date, this project is progressing with the relay logic development, testing with interfacing systems, software screen development, installations of communications equipment, and laboratory testing.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

Live front switchgear, terminations, Legacy SF6 switchgear and manually operated switchgear that cannot be retrofitted for remote operation.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
UG Automation	0.000	0.009	1.015	2.630	2.730	2.970	2.970

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Key learnings identified during the Charlotte Automation & Integration Pre-Scale deployment included the following.

- Prove or disprove long-standing assumptions about automation (e.g., automatic restoration versus manual restoration, peer-to-peer communications vs. centralized communications, etc.).
- Determine the need for strict uniformity (e.g., same firmware version in all locations) versus location-specific standards.
- Create Telecommunications standards for automation applications.

Benefits of this technology confirmed in the Charlotte Automation & Integration Pre-Scale deployment included the following:

- Reduced power interruptions: Minimizing the number of impacted customers due to potential equipment failure through remote asset monitoring for proactive maintenance.
- Improved asset utilization: Provide real time data and control of system, a functionality which does not exist today.
- Enable ability to do planned switching
- Enhanced fault locating
- Enhanced monitoring and maintenance of assets and inclusion of intrusion alarming
- Power quality: Enables planning and load growth data

Additionally, there are key intangible benefits of providing vital information for future projects of this kind and the safety aspect of minimizing the need for workers inside of the underground vaults.

Enterprise Distribution System Health Tool

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objectives of the enterprise distribution system health (EDSH) tool are to create an analytic model with actionable circuit – level information on reliability CSAT, Asset, and Vegetation for use by planning to provide a basis for prioritizing work to achieve the highest possible benefits in terms of customer reliability and cost reduction. The scope of the project consists of developing a platform using SAS tools and web-based user interface using Visual Analytics that can display corridor and/or protective-device level information; identify circuit and device level areas for analysis, attention and investment, and identify circuits that require incremental work. Business processes and change management is also included. The asset has a life expectancy of 5 years.

(ii) The status and timeframe for completion.

This project was initiated in 2016. The EDSH v1 Go-Live was in Q2 2016 and v2 Go-Live was in Q4 2017. The v3 Go-Live target is scheduled for Q1 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This is a new application for Duke Energy

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul estimate	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
EDSH	0.256	0.444	0.225	0.380	0.188	0.000	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses

Analysis mostly included identification of the benefits of this system.

- Reduce capital by extending life of assets.
- Reduce O&M by condition based maintenance or data driven maintenance schedule.
- Optimizing maintenance programs based on analytic scenarios (e.g. vegetation, maintenance program)
- Improving real-time operations from analytic insights (e.g.; outage durations, response for maintenance and restoration)
- Enable the retrieval of data, analytics insights and system status in a more efficient manner.

- Provide grid investments vegetation and other asset management data in an efficient manner to assist with the selection, prioritization and management of the Targeted Underground initiative.

Transmission System Modernization, Automation and Intelligence

Upgrade electromechanical relays to digital/electronic

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The intent of this System Reliability Program (SRP) is to systematically replace all Electromechanical and Solid State relays, both Transmission and Distribution class, for all elements (line terminal, bus, transformer, breaker failure, etc.).

These relays have been installed as far back as 1960 and are well beyond the end of their useful life. A majority of the line relays were installed in the early 1970s, which still exceed the relays' useful life of 30 years according to EPRI's "Protection Equipment Asset Management Analytics Development" for relays designed with cylinder units with capacitors. Solid State relays have a significant number of electronic components with a definite life, which is shorter than electromechanical relays.

Technology used in the protection and control industry has changed from electromechanical to solid state to microprocessor-based platforms. This change in technology has also increased the use and sophistication of various communication protocols and media. The need for more device functionality has accelerated because of the following factors:

- More demanding regulatory requirements
- Advances in technology
- Demand for operational data
- Demand for increased performance and reliability

The deployment of microprocessor-based protection system provides the following benefits:

- Flexibility in operating the system
- Improved fault-location capabilities
- Supports reduced outage restoration times
- Additional data available about the performance of the system and reliability insights

(ii) The status and timeframe for completion.

Replacement of electromechanical and solid state devices has been ongoing for many years, however they still make up approximately 40% of the relays installed on the DEC system. The program will be reviewed and executed over a 5-year period, after which the program will be re-evaluated for continued execution.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The electromechanical and solid state relays being replaced will be rendered obsolete with no expected salvage value or alternative uses.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section in not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul Estimate	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Digital Relay	0.000	0.000	0.000	2.438	14.625	14.375	14.300

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Installations are determined by location of the assets within scope of the program. Several factors are evaluated to determine priority of replacement including, but not limited to: performance history, location criticality, customer sensitivity, additional scheduled capital work at specific locations, and preventive maintenance due.

Remote Control Switches

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Transmission SCADA technology includes the deployment of remote control capabilities to existing switches, or in some cases net new switches that include remote control capability. This technology provides additional flexibility to the system operator in order to configure the system as necessary and vastly increases the resiliency of the Transmission grid. This additional capability supports increased capabilities to isolate equipment for maintenance purposes as well as isolate failed or damaged equipment during events. Remote switching capability can decrease restoration times following outages thus minimizing disruption to customers. This capability being widely enhanced across the service territory also provides increased capabilities during significant storm events to be able to isolate impacted areas and increase the ability to rapidly restore service to a larger portion of customers.

(ii) The status and timeframe for completion.

Installation of remote controlled switches has been ongoing for many years; however, the program is still in the early stages of completion in DEC. The Company aims to substantially advance this program that systematically identifies new locations to add remote control capabilities to existing switches, or net new switches with remote control capabilities are determined. The program will be reviewed and executed over a 5-year period, after which the program will be re-evaluated for continued execution.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

No existing equipment is expected to be rendered obsolete by the new technology, unless an existing switch is completely replaced during a project due to poor asset health. In this instance there would be no salvage value of the obsolete equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The technology does not contain any information that would be collected or shared with customers.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

The technology does not contain any information that would be transferred to, or used by, third parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in Millions	actual	Jan-Jul estimate	Aug-Dec estimate	actual	actual	actual	actual
Project	2017	2018	2018	2019	2020	2021	2022
Control Switches				0.813	2.438	2.563	2.563
SCADA Installations				0.000	0.589	0.589	0.589

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs

used to perform the analyses.

Installations are determined with consideration to several factors used to determine priority including, but not limited to: operational and performance history, location criticality, customer sensitivity, number of customers served, line and system configuration, additional scheduled capital work at specific locations, and exposure of line section length.

Condition-Based Monitoring (CBM)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Condition-Based Monitoring (CBM) program will install new monitoring technology. The CBM system consists of online transformer monitoring for key parameters to allow operations staff to continuously assess the condition of a transformer and its bushings from locations remote to the substation. The system will be installed on transformers throughout the Duke Energy system based on each transformer's criticality to the system, its condition, age, and known operational issues that can impact the transformer's reliability and availability. The monitoring system consists of a commercially available multi-gas monitor and moisture monitor for the main tank of the transformer, a multi gas monitor for the tap changer compartment for load tap changing transformers (LTCs), a bushing monitor system, and a communication system for collecting the data and integrating it into the enterprise system.

(ii) The status and timeframe for completion.

Full deployment is expected to start Q4 2018 with approximately 10 sites per year for the next 5 years.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

There is no existing equipment being removed. The project is adding monitors to transformers to remotely monitor the health of the transformer.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec actual	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
Full-Scale	0.000	0.000	0.000	0.585	2.115	2.115	2.115	2.115

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The sensor technology selected was informed by a pre-scale project that occurred at Duke Energy in 2016 and 2017. The projected benefits of an online transformer monitoring system are as follows:

- System Monitoring – The monitoring system will provide real-time information on system and component condition.
- Reliability Improvement – The early warning offered by a transformer monitoring system can lower the risk of an unscheduled outage, and minimize the severity and duration of the problem through early identification.
- Defer capital investment of existing transformers.
- Avoidance of the potential environmental impacts associated with transformer failures. Catastrophic transformer failures (of types that could potentially have been detected by the proposed monitoring system) release oil into the substations and the surrounding areas.
- O&M Cost Management – Routine diagnostic tests such as oil sampling and off-line bushing tests can either have their intervals extended or eliminated for those transformers that have the monitoring system. Manual oil sampling and off-line bushing power factor tests will be performed when the monitoring system indicates a significant change in operating condition.

Phasor NXT

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

PMUs are a key component of Transmission's long term vision. Duke Energy is committed to the deployment of PMUs across the enterprise. The GS PhasorNXT project will support this vision by providing the software required to support the PMUs, and leverage the PMU data for system visibility, state estimation and post event analysis. PhasorNXT is a comprehensive platform that integrates synchrophasor-based linear state estimation and real-time wide-area visualization technology to provide a state of the art synchrophasor monitoring platform. PhasorNXT will deliver to operators improved synchrophasor data quality, expanded visibility beyond available PMUs by calculating virtual PMU values, state estimated values based on *e*LSE (*enhanced* Linear State Estimation), one-line diagrams and visualization for situational awareness monitoring using RTDMS. Operators will have the ability to view the system geographically via PhasorNXT Visualization Client displays, or using the one-line diagrams with zoom in capability.

(ii) The status and timeframe for completion.

The project is expected to be completed in Q4 2018.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable. The project installs new servers only.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
Phasor NXT	0.00	0.249	0.055	0.123	0.000	0.000	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The analyses for Phasor NXT is primarily part of the PMU Project. Pertaining to the PhasorNXT software, multiple instances were needed due to NERC CIP Architecture Policies and the need to align the instances to the various jurisdictional ECC's and the ECC practice where all apps reside within a 6-walled data centers.

Transmission Health and Risk Management

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objective of the Health Risk Management (HRM) is to extend the lifecycle of aging assets, in particular transformers, and reduce the risk of asset failures that can lead to outages by shifting from a reactive to a proactive/predictive model by utilizing component, asset, fleet, and system health and risk data. A new HRM platform for collecting and analyzing data will be implemented.

(ii) The status and timeframe for completion.

Planning for this project began Q4 2016 and ended Q4 2017 when the project was approved. The design phase took place from Q4 2017 through Q1 2018. The initial Go-Live date which will include transformer data is Q3 2019 for DEC. The Go-Live date for circuit breaker data is Q1 2021 for DEC.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This is a new application for Duke Energy.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec actual	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
HRM	0.256	0.444	0.225	0.380	0.188	0.000	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Benefits expected from the implementation of the Transmission HRM system include:

- Reduction in Emergent and Emergency Transformer/Equipment Replacements leading to cost saving
- Deferral/improvement in capital efficiency through predictive intelligent asset management

- Extend the lifecycle of the aging assets
- Use dynamic automated watch lists
- Shift from reactive to proactive asset management
- Improve Asset Visibility and reporting across the enterprise
- Improvement of capital and O&M, managing incremental costs with asset growth
- Providing fleet level risk indices
- Decrease Emergent and Emergency Truck Rolls

Overall Savings due to personnel operational efficiencies:

- Ability to capture within a system asset knowledge
- Elimination of manual efforts
- Decrease in emergency and emergent call outs
- Prioritizing Projects and Maintenance
- Prioritizing Replacements and Maintenance
- Remote access to equipment data and analytics

Predictive asset health and risk driven work schedules, as opposed to calendar based schedules**:**

- DGA Testing w/ DGA Monitors in place
- CB I2T loss, breaker wear w/ CB Monitors in place
- Power Factor testing w/ Bushing Monitors in place

Reduction in SAIDI

Communications

Grid / Business Wide Area Network – Core/Edge Network Uplift

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Today, DEC uses large carrier grade routers to serve as the core networks for its Grid and Business wide area networks (WAN). The DEC Grid and Business WANs are physically separate networks. The DEC Grid WAN provides network connectivity to DEC substations. Data network equipment such as routers and switches are deployed at the DEC substations for termination of the Grid WAN connections. The Grid WAN core routers are located at major Telecom communication hubs throughout the DEC service territory, including the energy control centers where the head-end SCADA systems reside. The combination of the core and substation routers make up the DEC Grid WAN, which enables the DEC SCADA systems and other grid applications to monitor, control and manage the electrical grid assets and network.

The DEC Business WAN utilizes a separate set of large carrier grade routers to provide network connectivity for DEC facilities that need to access business specific or enterprise applications, physical security systems, and telephony and radio systems. The DEC sites that leverage the Business WAN include Transmission and Distribution Operations Centers, Power Plants, Energy Control Centers, Data

Centers, Customer Call Centers and Regional Corporate offices. Edge routers and switches are deployed at these facilities for termination of the Business WAN connections.

The DEC Network Uplift initiative includes efforts to replace end of life network equipment used on the DEC Grid and Business Core WANs, and deployed in DEC substations and Transmission and Distribution operations facilities. The end of life data network hardware will be replaced with current technology. The Core WAN uplift is being redesigned and may result in consolidating the two separate Grid and Business networks in place today with a single network with virtual capabilities to segment and secure different types of network traffic. This change would improve operational efficiency of the Core network, while still maintaining the levels of security needed for Grid and Business communications.

The DEC Network Uplift initiative also includes implementing a feature called Dynamic Multipoint Virtual Private Network (DMVPN) to improve automated rerouting of substation SCADA traffic due to various network outage scenarios. Secondary or back-up network connections such as cellular are needed for DMVPN; therefore, these projects will add secondary connections where needed.
All data network equipment (routers and switches) have an expected average life of 5 – 7 years.

(ii) The status and timeframe for completion.

The projects in the DEC Network Uplift initiative are a complex undertaking starting in 2018 and will take 3-5 years to complete. However, the duration of the project may change depending on the final design, ability to schedule outages, and availability of resources and funding.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The equipment that is being replaced by the DEC Network Uplift initiative includes core and edge routers and switches. The full list of equipment being replaced in DEC will be identified and documented during the projects. The anticipated book and salvage values of this equipment at time of retirement will be $0, and there is no alternative use for this equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The DEC Grid and Business networks are implemented solely for conducting internal Duke Energy business. The DEC Grid Core/Edge network, which is a dedicated and secure network, is not used to transfer data between Duke and its customers. The Business WAN core is also a dedicated and secure network that mainly provides connectivity for internal DEC facilities.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

Duke Energy may contract with third parties to provide engineering and/or installation services for the DEC Network Uplift projects. Third parties would not have access to the DEC Grid and Business networks after their work is complete. Third parties will not have access to customer-specific information during their work and after their work is complete.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
GridWAN / BizWAN Network Upgrades	0.000	0.005	0.770	6.869	7.652	8.328	2.907

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The current DEC Core network router technology has reached manufacturer end of life and is currently experiencing some reliability issues, thus creating a need to replace the current hardware to maintain operational reliability of the Grid and Business networks. Duke Energy Telecom created a request for proposal (RFP) in 2017 and distributed it to several network vendors. The purpose of this RFP was to seek solutions for redesigning the Grid and Business WAN core networks, and replace the end of life Cisco hardware with new technology and functionality. Duke Energy selected a Cisco solution and is currently working with Cisco and one of its affiliates to complete the design of the WAN core networks. The design phase will determine what hardware and features are needed and where equipment will be installed. Additionally, edge network hardware (routers and switches) at Grid (substations) and Business facilities will be replaced with current Telecom equipment standards at the point they are deemed to have reached their end of life. The DMVPN technology for the DEC Grid WAN is being deployed based on new Duke Energy Telecom standards to improve reliability and resiliency of substation communications.

Next Generation Cellular

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

A significant number of the cellular connections at Duke Energy are on cellular 2G/3G networks that are end of life. Duke Energy is working with the cellular carriers to transition these connections to their LTE networks. The Next Generation Cellular initiative will replace existing legacy 2G/3G cellular modems for DEC distribution line devices and substations. These modems, which have exceeded their life expectancy of 3 – 5 years, will be replaced with 4G modems, and 5G modems when available. The current 4G and future 5G cellular technologies provide greater network bandwidth or throughput, lower latency or response time, and better cybersecurity protections. The new 4G and 5G modems will also have a life expectancy of 3 – 5 years.

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(ii) The status and timeframe for completion.

The Next Generation Cellular effort started in 2017 and will continue through the end of 2022.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The 2G/3G cellular modems being replaced were installed in 2012 and prior years. The anticipated book and salvage values of this equipment at time of retirement will be $0, and there is no alternative use for this equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Cellular communications for DEC Grid substations and Distribution line devices are not used to transfer data between Duke Energy and its customers.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

Duke Energy will use internal resources to engineer and install new the new 4G/5G modems for the DEC Next Generation Cellular effort. Third parties may be used to assist in configuration of the new modems prior to activating them on the cellular network, or installing and commissioning them in the field. Third parties will not have access to customer-specific information during and after their work is complete.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

($ in thousands)

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Actual	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
DEC Next Gen Cell Modems	0.954	0.308	2.515	2.124	1.360	1.094	0.432

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Replacement of the 2G/3G modems is required because carrier 2G/3G cellular networks are end of life. Modems that are targeted for replacement were identified through a review of Duke Energy and carrier asset inventory data. The hardware chosen to replace the 2G/3G modems is based on current Duke Energy cellular modem standards.

Strategic Fiber & Wireless Transport

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Strategic Fiber & Wireless Transport initiative provides for the end of life replacement of Duke Energy privately owned fiber and wireless transport systems. These systems are the backbone of Duke Energy's private network, providing Grid and Business network connectivity to DEC substations, operations facilities, energy control centers, generation plants, customer call centers, data centers and corporate offices. Most of Duke Energy's internal Grid and Business functions traverse its fiber and wireless transport systems. Replacement of these end of life systems is needed to improve network reliability and resiliency, increase data network capacity, support changing security requirements, reduce O&M expenses, and foster technology transformation. The table below describes several work streams within the Strategic Fiber and Wireless Transport initiative that improve Duke Energy's backbone communications infrastructure.

Technology	Description	Expected Life Cycle
Fiber optic cable	The backbone of Duke Energy's communications network (a.k.a. the 3rd Grid) is the transport network, which consists of fiber optical cable and microwave systems. A recent current state assessment identified 1,750 miles of fiber optic cable that needs to be evaluated for replacement based on age and performance. Much of this fiber has already reached or exceeded its typical industry life cycle of 20 – 30 years, depending on the fiber type, application and installation location. New fiber cabling will have a similar life cycle. Additionally, Duke Energy will expand its fiber network to connect key generating plants, operations centers, substations and other critical facilities to satisfy business needs. The Fiber Optic Cable work stream has begun replacing end-of-life fiber optic cable and constructing new fiber routes based on business needs. This work stream is also investigating alternatives to using optical ground wire (OPGW) to enable Duke Energy to deploy fiber faster and less costly.	Typical life cycle of fiber optic cable is 20 – 30 years.
Microwave	Like fiber, microwave provides high capacity connectivity to the core Duke Energy communications network. Much of the current microwave uses obsolete TDM technology, with capacity that is not meeting current business needs. Microwave is an important part of the Duke Energy transport network as it provides high speed connectivity in areas where	Typical life cycle of microwave radio systems is 10 years.

Technology	Description	Expected Life Cycle
	installing fiber is not economically feasible. Many of Duke Energy's microwave systems in place today are end of life and manufactured discontinued, or are not meeting business capacity needs. These systems will be replaced with equipment, which is Duke's current MW radio standard.	
Optical systems	Optical systems are the electronic systems that "light" the fiber optic cable and send signals through the fiber optic cable for communications. Much of Duke Energy's optical systems use SONET/TDM technology, which is becoming obsolete and manufacture is discontinued. The five-year technology plan has identified optical nodes that will need to be replaced, removing SONET/TDM systems and installing the latest packet-based technology that provide more capacity. Duke Energy will be installing new optical equipment that will position Duke Energy for the next 10 years of bandwidth expansion and modernized IP/Ethernet services.	Typical life cycle of optical systems is 10 years.
MAS Radio	Multiple Address System (MAS) are radios that provide "last mile" wireless connectivity for substations. MAS technology is a low speed/low bandwidth system that is typically suited for serial data connections to low speed SCADA devices. Much of Duke Energy's MAS radios are end of life and manufacture is discontinued, and will be replaced by newer technology, such as point-to-point and point-to-multipoint radios.	Typical life cycle of radio transport systems is 10 years.
Tower and Shelters	Many of Duke Energy's communications towers, shelters and DC power systems must be replaced due to age, structural issues and capacity. Duke Energy is planning to replace towers, shelters and DC power systems in multiple locations across its entire service area. The Tower and Shelter Replacement project will address all facets of the tower and shelter work, including initial inspection, engineering, regulatory work, obtaining right of ways, completing construction and performing final inspection.	Typical life cycle of communications towers is 40 – 50 years, depending on environmental conditions, weather, preventive maintenance and tower loading. Typical life cycle of communication shelters or buildings is 25 – 30 years, depending on environmental

Technology	Description	Expected Life Cycle
		conditions, weather and preventive maintenance. Typical life cycle of DC power systems is 7 – 10 years; however, batteries are typically replaced about every 5 years.

(ii) The status and timeframe for completion.

The Strategic Fiber and Wireless Transport work streams in DEC are underway and will continue for the next 10 years.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The fiber optic cabling, optical systems, microwave systems, communication towers, communication shelters and DC power systems and batteries that will be decommissioned during this work stream will be rendered obsolete by the new technology installed. The anticipated book and salvage values of this equipment and hardware is anticipated to be $0. Some of the optical and microwave electronics may be used as spare parts in the interim until all related systems have been removed from service.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Duke Energy private fiber and wireless transport systems are not used to transfer data between Duke and its customers. These systems are implemented solely for conducting internal Duke Energy business.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

N/A

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
DEC Fiber Optic Cable	0.113	5.615	5.913	5.662	21.745	23.595	8.272
DEC Microwave Systems	0.000	0.755	0.760	1.820	5.724	6.211	2.178

DEC Optical Systems	0.000	0.709	0.250	0.614	1.931	2.095	0.734
DEC MAS Radios	0.000	0.191	0.079	0.097	0.306	0.332	0.116
DEC Tower and Shelters	0.163	1.032	2.706	1.038	2.478	2.478	2.478

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Duke Energy has noted that many of the systems, equipment and physical infrastructure of Duke's backbone network are at or near end of life, or facing constraints on network capacity that are impacting business performance and reliability. The Strategic Fiber and Wireless Transport initiative was established to address these end of life, capacity and reliability issues associated with fiber optic cable, optical systems, microwave radio systems, MAS technology, and communication towers, shelters and DC power systems. Duke Energy Telecom will replace obsolete equipment, systems and hardware with current standards. Where necessary, Duke Energy Telecom will create RFP's to evaluate new technology, equipment, systems, hardware or vendors and select the most appropriate and cost-effective path for replacement. Duke Energy has already utilized the RFP approach to make technology decisions for new optical systems, microwave radio systems and MAS replacements. Telecom also used the RFP process to select vendors to replace communication towers and shelter.

Energy Storage

Energy Storage Control System

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Energy Storage Control System (ESCS) Project scope develops and deploys a battery storage Head End monitoring and control system for remote access and control to every grid scale, grid connected battery storage site deployed by Duke Energy. The Head End will provide monitoring of operations and health conditions information to multiple groups and an overview of battery storage operations across the entire Duke Energy grid. The Head End software will provide individual or aggregated battery site remote control, as needed, to alter battery use schedules or operational parameters for changing business needs. The Head End will also enable the aggregated use of battery storage sites for local or bulk energy support in the near future.

The Project deliverables include the software solution for monitoring and operations required for both storage and solar-plus-storage energy business use cases. The primary control applications will include:

- Frequency Regulation support for Duke Generation
- Energy Arbitrage – shifting energy use (charge off peak, discharge on peak)
- Grid Islanding for outage support and peak shaving

The ESCS software will also provide battery storage system health and operations monitoring functions including:

- Substation Load Monitoring to avoid asset overload condition
- Battery System Operations Monitoring, Alarming & Remote Notification
- Cycle Maintenance Management – Maintenance per component (battery system, HVAC, Inverter)

.(ii) The status and timeframe for completion.

Vendor selection, project planning and contract development for the ESCS Project began in January 2018. The in-service date is expected to be in late 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The project does not replace any systems or equipment currently in place.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
ESCS	0.000	0.063	0 .530	1.536	0.244	0.244	0.122

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Duke Energy submitted a Request for Information (RFI) mid-2017 to 18 software suppliers that provide control systems for battery storage. Duke reviewed each vendor submitted proposal and ranked each supplier according to their written response. From this evaluation the sub-team selected a short-list of suppliers. An RFP was issued to the three short-list suppliers in November 2017. The sub-team evaluated each RFP submission and held face to face interviews and system demonstration with each supplier. The sub-team further scored each supplier from these RFP sessions and selected a preferred supplier to carry into contract negotiations.

AMI

DEC submitted the May 5, 2017 Supplemental Information filing in Docket No. E-100, Sub 147 to the 2016 Smart Grid Technology Plans outlining its AMI deployment.

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Advanced Metering Infrastructure (AMI) is the foundational investment that will enable enhanced customer solutions - giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and save money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy usage, and ultimately, their bills. The Company also expects AMI meters to result in reduced truck rolls with remote capabilities to operate internal switch for majority of meters.

Deployment of smart meters allow customers to start, stop and move service without the need for a technician visit. The smart meters also help provide an interface for customers to see and understand their hourly energy usage, allowing them to better manage their consumption and, as a result, their bills. Smart meters have enabled current customer programs such as support for net metering, outage notification alerts, mid-billing cycle usage alerts, and the ability for customers to select their payment due date. They help enable possible future customer programs such as a real-time usage application for smart phones. The technology can also help enable future energy efficiency options and potential time-of-use rate offerings as well as pre-payment programs.

These new meters are directly interoperable with the existing AMI systems and will be depreciated over a period of 15 years pursuant to the terms set forth in the Company’s last rate case proceeding Order entered June 22, 2018 in Docket No. E-7, Sub 1146.

(ii) The status and timeframe for completion.

Through August 2018, DEC has installed a total of approximately 860,562 smart meters in NC. DEC NC AMI installations are expected to be complete in 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing

equipment.

DEC expects to replace approximately 1.32 million Automated Meter Reading (AMR or "drive-by") meters over the three-year period beginning in 2017 and ending in 2019. The estimated salvage value of those meters is $1.37 M. The remaining net book value of the meters being removed is estimated at $130.97 M as of March 31, 2018.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Smart meters capture energy usage and send it to grid routers directly or through range extenders and/or other meters to form a radio frequency (RF) mesh network, or via cellular Direct Connect. The grid routers transmit collected usage data to the AMI headend system via cellular backhaul once each day. The head-end system acts as the data collection point inbound from the metering network infrastructure, as well as providing meter command and encryption key management outbound. The data is then sent to a Meter Data Management (MDM) system which provides billing determinants to the customer billing system for billing.

The data collected by the AMI meter utilizes a unique meter number (not displayed on the meter face) and thereby contains no personally identifiable customer information. All data is encrypted at the meter and decrypted at head-end system. The meter number is then used as the linkage to other information within the customer billing systems.

See SGTP Exhibit 2 - Commission's Rules on Third Party Access to Customer Usage Data for additional information related to how the utility provides usage information to customers through the secure online customer portal and billing statements.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not currently involve the transfer of customer information to any third-parties. Refer to Exhibit 2 for general information on providing data to customers and third parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

DEC has incurred approximately $264 million in capital through August 2018 on the AMI deployment project covering both its North and South Carolina service territories. Based on the most recent cost estimate for the project, the forecast costs are outlined below:

DEC AMI Capital Forecast (NC and SC)	**Inception to date (actual)**	**Sept-Dec 2018 (estimate)**	**2019 (estimate)**
Annual Capital $ (millions)	$263,968,155	$16,047,850	$2,972,368

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The Cost-Benefit Analysis attached as Appendix C, Exhibit A to DEC's 2017 Smart Grid Technology Plan Update[1] was presented to Company management for consideration of the project.

Customer Programs

Outage Notification

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Company started the Outage Initiatives (AMI) project in Q4 2017 to use smart meter data and technology to detect customer outages and restorations and identify meters mapped incorrectly in order to improve the accuracy and timeliness of customer communications sent during an outage. If an outage or restoration is detected, a text message is automatically triggered and sent to the customer via email, text message, or automated outbound voice call to the phone number on file with the Company to inform them of the outage, provide a status update with estimated time of restoration, and confirm when power has been restored. This program is designed to improve customer satisfaction during an outage by enabling the Company to provide more reliable, accurate, and timely information to customers, minimizing the need for customers to self-report an outage. This program is designed to improve the customer experience during an outage by utilizing AMI technology to further improve upon existing outage alerts and communications. Using AMI technology, the Company can develop outage alarms to detect when an AMI meter is not responding and can alert the customer, providing them with more reliable and timely outage information. The majority of this software and technology is already in place and utilizes technology and data afforded by AMI meters.

(ii) The status and timeframe for completion.

The complete roll-out of the functionality and program is aligned with the deployment of AMI meters across the jurisdiction.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable.

[1] Pursuant to Commission request, DEC also completed revised cost-benefit analysis and filed it in Docket Nos. E-7, Sub 1115 and E-100, Sub 147on December 15, 2017.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The Company transfers outage information to the customer via text, email, or voice channel, based on customer selected preference. The Company does not transfer any personally identifiable customer information. Due to the information not containing PII data, there is no need to encrypt or provide additional security in the messages sent. However, we do comply with all TCPA standards regarding spam, out-out, etc.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

The approximate capital expenditure approved for 2017 and 2018 for DEC in North Carolina was $126,003 and $1,113,441, respectively, of which approximately $558,441 has been spent as of July 2018.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

JD Power customer survey results consistently indicate that customers are more satisfied when their utility offers them outage status communications.

Completed Projects

The following information provides a summary of DEC projects which have closed since the 2016 Smart Grid Technology plan was submitted.

Large Commercial & Industrial (C&I) and Special Meter AMI Conversion

Across the DEC territory, there were a total of approximately 3,100 meters that were exchanged with an AMI meter within the scope of this project. A small subset of customers within the DEC service territory had meters which were read via cellular communications or manual "walk-by" readings. These included some large C&I customers, customers participating in solar PV Net Metering, as well as those with load research meters. Managing these separate meters and systems were costly due to the manual nature of the processes involved as well as the meter hardware and reading costs. These new meters are directly interoperable with the existing AMI meter systems and have a planned life of approximately 15 years. The AMI system, already in place through the initial DEC AMI deployment, is able to meet the billing requirements for the majority of these customers, and will reduce the complexity of supporting these customers.

Yukon Feeder Automation Upgrade

Duke Energy used a bolt-on central management software to manage and control its Self-Healing Networks across the enterprise. This software did not have functionality to control Self-Healing Networks in areas with high Distributed Energy Resource (DER) penetration. Distribution feeder circuits with a high penetration of DER were disabling their self-healing network functionality. With the increased growth of distribution connected DER, there was an increased need for software functionality that incorporates DER in its behavior. Therefore, the Enterprise Project upgraded the software to the latest version with the DER functionality. In conjunction with this upgrade, new security functionality was also provided by the vendor and deployed as part of the scope of this effort across the enterprise. This project was completed in Q3 2017. The total costs at completion was $0.5 million for DEC.

IVVC Pre-scale Deployment

This project was a small-scale installation of Integrated Voltage/Volt-Ampere Reactive Control (IVVC) technology within the DEC service territory. IVVC, sometimes referred to as conservation voltage reduction, is one of the first advanced distribution management system (DMS) functionalities to be installed in the DEC territory and has the potential to reduce overall system demand and energy consumption by optimizing voltage and reactive power flow (VARs) across the distribution network under all load conditions. Potential customer and business benefits from a broad IVVC deployment include more efficient energy delivery via less technical line losses, deferred investments in peaking generation capabilities, reduction in the environmental impact of energy generation, improved energy efficiency, and more stable system voltages.

This pre-scale deployment project used real-time field conditions on a small scale to demonstrate the use of IVVC technology in the DEC system, and to validate the range of costs and benefits in order to better inform the full-scale deployment business case analysis for DEC. One of the primary variables to validate was the amount of voltage reduction capability that could be achieved with IVVC in the DEC distribution system. The project validated that full scale estimates of 2% voltage reductions and 1.4% energy can be expected depending on the amount of investment in the distribution system to condition circuits.

The pre-scale deployment was completed in Q4 2016 at a total cost of $5.5M. Six substations were upgraded with 19 circuits upgraded utilizing Circuit Conditioning criteria. Testing was completed to integrate real time data from the substation and circuit devices into DSCADA/DMS. Power Flow and LVM (IVVC) testing was completed to estimate IVVC benefits and validate IVVC functionality.

Distributed Energy Resources Management System (DERMS)

The DERMS Project was a research initiative to investigate and document how to effectively manage and utilize different types of Distributed Energy Resources (DERs) on the Distribution Grid. The DERMS project developed prototype DMS functionality to manage and mitigate the electrical system effects of growing distributed, renewable generation and storage capacity, and was tested with data from the

Duke Energy service area. Through implementation of DERMS functionality within our Distribution Management System (DMS), Duke Energy expects benefits to include:

- Mitigation and management of solar swing impacts to system stability
- Management of cold load issues to reduce outage time
- Management of distributed generation impact on transmission
- Enhanced circuit performance and optimization
- Enhanced distribution load forecasting

This project was being coordinated through a vendor partner which is receiving DOE grant funding. Duke provided the DMS test platform for this pilot. As of August 2016, the DERMS project had completed all analysis, development, testing and pilot activities and the project closed in Q4 2016 at a total cost of $185K.

Self-Healing Networks

Self-healing technology provides an immediate benefit of increased system reliability using distribution line power devices such as switches, programmable reclosers, and circuit breakers, that are automated and capable of communicating via an intelligent control system. The control system, communications system, and power line devices all work together as a "team", serving to identify and isolate the portion of the system affected by a fault or other problem, thus minimizing the impact to customers. The self-healing network of equipment communicates to reconfigure the distribution network optimally to minimize the extent of the outage, and restore power to as many customers as possible.

Each self-healing team is generally comprised of triple blade switches, three-phase electronic reclosers with cellular modem, and communication controllers capable of transferring load between multiple circuits. The Self-Healing Network provides SCADA data to the DMS automatically and can support operation autonomously or under control.

Benefits include reliability improvements through fault isolation and reduced Customer Minutes of Interruption. Additional benefits include more efficient outage response, reduced outage assessment time, and reduction in emissions and safety hazards associated with fewer miles driven by field crews.

Self-Healing Operations through 08/31/2018 (includes MED's)				
	SHT in Service	**Number of Operations**	**Customer Interruptions Avoided**	**Customer Minutes of Interruption Saved**
2012	14	12	14,344	1,550,065
2013	16	23	20,156	7,200,743
2014	37	12	10,937	1,475,680
2015	37	36	41,218	7,195,584
2016	38	40	40,224	6,182,806
2017	49	37	42,287	5,194,692

2018 YTD	53	30	31,907	4,408,464

Charlotte Automation & Integration Pre-Scale Deployment

An urban underground automation system is installed in locations where reliability can have a direct impact on safety, such as a downtown or dense multi-use location, or other places with high profile loads like airports, stadiums, etc. This technology responds to a loss of power by utilizing real-time data to isolate faults and reconfigure local distribution networks to minimize customer outages.
There are many benefits to an underground distribution automation system, including:

- Reducing the number of outages and improving the customers' experience
- Reducing the duration of outages, when they do occur
- Restoring power in 45 seconds or less in most cases
- Continuously assessing the state of the grid for potential issues that could arise

Duke Energy has made investments in various auto-throw over sectionalizing and isolation switchgear in the DEC jurisdiction. There is a large amount of this equipment located in the Uptown Charlotte area in underground vaults. This gear has been locally operated by crew members entering enclosed spaces, requiring the crew member to open a control panel and potentially a dead-front style switch cabinet to operate the gear. From an asset maintenance perspective, if a relay or battery failure occurs, the only way that the Company would know that this event had occurred would be as the result of a customer outage related to equipment failure or annual maintenance inspections.

The goal of the Charlotte Automation & Integration (A&I) proof of concept is to place new communication and logic settings in the relays, create DMS control and alarm monitoring screens, install communications gear, and commission and check out the control and equipment to allow for Grid Management/Distribution Control Center to remotely monitor and control the switchgear. This will allow for switchgear to be operated remotely, promote system awareness of fault and other system event locations, allow crew members to not be in the proximity of the gear while it is being operated, and enhance system asset maintenance. This project provides visibility and automation to underground vaults in downtown Charlotte by integrating the distributed automation control system into the existing Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS) through a fiber optic communication network. The project closed in Q3 2018 with a preliminary final project cost of $0.7M

Small Electronic Sectionalizing Device (Fuse Save) Proof of Concept

Duke Energy has deployed small electronic sectionalizing devices that are installed in place of a fuse to protect a line segment. The small electronic sectionalizing devices can avoid customer outages by operating to allow a temporary fault to clear the line instead of a having a blown fuse with a sustained customer interruption. The small electronic sectionalizing devices can also eliminate momentary interruptions on the feeder in instances where the breaker is tripped to save the lateral fuse during a

fault. The objective of the enterprise-wide proof of concept project was to explore potential methods of reliability and operational improvements using the small electronic sectionalizing devices.
Benefits included:

- Reduce sustained interruptions through improved fuse save
- Reduce momentary interruptions through improved coordination
- Reduce interruption risk through improved Hot Line Tag (i.e. non-reclosing) capability

The small electronic sectionalizing device Proof of Concept was used to validate the functionality of the small electronic sectionalizing device in real world conditions. The original use case deployed devices across the enterprise in small numbers. It included a bypass fuse and line sensor which added additional cost and complexity to the installation. The updated use case for this Proof of Concept is the fuse replacement with electronic reclosing device project which is a targeted strategy for an area. The project closed in Q2 2018 with a final project cost of $0.2M.

Usage Alerts

The Usage Alerts program is designed to provide residential and small and medium business customers more transparency into their actual and projected electricity costs. Customers with a certified smart meter and email address on file with Duke Energy are automatically enrolled to receive a 'mid-cycle' email halfway through their billing cycle each month. This mid-cycle alert contains the customer's estimated electricity cost to date and projected cost for the month based on the customer's smart meter data and rate schedule. It also includes an estimate of the customer's electricity cost to date by major appliance and useful tips to help customers be more energy conscious and efficient. Customers have the option to further customize their alerts by enrolling in text message notifications and/or budget alerts, and updating their home profile information. Budget Alerts notify customers when they reach 75% and 100% of the dollar amount they indicate in their alert preferences.

Pick Your Due Date

The Pick Your Due Date (PYDD) program allows residential and small and medium business customers to choose the bill due date that best meets their personal and financial needs. Customers can choose any date and can update their selected date one time each year. The program leverages smart meter capabilities such as remote meter reading to allow customers to select a due date outside of their pre-determined meter reading route schedule without creating meter reading inefficiencies.

4. Technologies Actively Under Consideration

Reference	Requirement
R8-60.1 (c) 4	*For all smart grid technologies actively under consideration for implementation within the next five years, the smart grid technology plan shall include a description of the technologies,*

	including the goals and objectives of the technologies, as well as a descriptive summary of any completed analysis used by the utility in assessing the smart grid technology.

Integrated Voltage and VAR Control (IVVC)

Integrated Voltage/VAR Control (IVVC) is the coordinated control of distribution equipment in substations and on distribution lines to optimize voltages and power factors on the distribution grid. This allows the distribution system to operate as efficiently as possible without violating load and voltage constraints, while supporting the reactive power needs of the bulk power system. IVVC can be implemented through various Substation and Distribution projects included within the Duke Energy Carolinas (DEC) IVVC Evaluation. Currently, communication with and control of substation voltage regulation, substation capacitors, and distribution line voltage regulators on the DEC system is minimal. Additionally, distribution line capacitors have communications, but not remote control, capabilities. Primary projects to install communications and control infrastructure include Substation Voltage Regulator Control Replacement, Substation Capacitor Control Replacement, Distribution Line Voltage Regulator Control Replacement, Distribution Line Capacitor Control Replacement, possible installation of End of Line Medium Voltage Sensors, and two-way communications implementation into these substation and distribution line devices. New Distribution Line Voltage Regulator and Capacitor additions are also possible. Other proposed projects, such as the Self Optimized Grid, overlap in providing some of the infrastructure and capabilities necessary to enable IVVC. Therefore, Duke Energy Carolinas could take advantage of resource and scope opportunities from all the projects combined to make IVVC possible.

IVVC can dynamically optimize the control of substation and distribution devices, resulting in a flattening of the voltage profile across an entire circuit, starting at the substation and continuing out to the farthest endpoint on that circuit. This flattening of the voltage profile is accomplished by integrating substation and distribution line voltage regulators and capacitors into the Distribution Management System (DMS) with two-way communications, automating their operation. The DMS continuously monitors the conditions on the controlled circuits and maintains the desired voltage profile. Once the system is operating with a relatively flat voltage profile across an entire circuit, the resulting circuit voltage at the substation can then be operated at a lower overall level. Lowering the circuit voltage [conservation voltage reduction (CVR)] at the substation results in a reduction of system loading, creating the benefit of decreased generation. CVR is an operational mode of Volt Var Optimization (VVO) that supports voltage reduction and energy conservation. This provides fuel savings to customers and reduced emissions from the avoided generation.

IVVC provides increased visibility into the status and condition of substation and field devices such as capacitor banks, voltage regulators, and transformer load-tap changers. This added visibility and enhanced voltage control will help manage the integration of distributed energy resources (i.e. solar) by improving the grid's ability to respond to intermittency. Access to additional system data will aid grid operators in the daily operation of the distribution grid and promote reliability. CVR functionality would target a potential 2% voltage reduction on the circuits and substations within the scope of implementation. This scope accounts for approximately 50% of the total circuits and substations across DEC, which account for approximately 70% of current base load. Assuming an average CVR factor of 0.7 (CVR Factor = % Load Reduction / % Voltage Reduction) this 2% voltage reduction is estimated to result in a 1.4% load reduction for enabled circuits. There may be cases where a variation in voltage could impact customers with large motors sensitive to voltage control. The DMS system can be designed to manage distribution circuits serving loads with voltage sensitivities, reducing these impacts. It is expected that CVR functionality would be utilized for the majority of the year. However, CVR mode would provide less demand reduction capability than peak shaving mode. To maximize operational flexibility and value, the IVVC system will also have peak shaving capability and emergency modes of operation. The software within the future enterprise DMS platform will enable IVVC to operate in various modes to provide further customer benefit.

Benefits:

- Reduced distribution line losses due to lower overall voltage
- More efficient grid due to lower line losses and reduced reactive power
- Less generation fuel consumed and lower emissions due to grid efficiencies
- Integrated control of capacitor banks provides greater ability to reduce reactive power, resulting in less apparent load on the system
- Less peak load on the grid could result in a reduced need to build additional peaking generation
- Optimized control of volt/VAR devices improves the grid's ability to respond to intermittency
- Helps to manage integration of distributed energy resources

As part of the settlement agreement with EDF in the Piedmont merger docket E-2, Sub 1095 and E-7, Sub 1110, Duke completed a cost-benefit analysis for a broad deployment of Integrated Volt-Var Control in DEC territory, similar to deployment plan developed for Duke Energy Indiana. The results of the analysis are included with the 2018 SGTP Filing Exhibit 1 – DEC IVVC Cost Benefit Analysis.

Battery Storage and Microgrids

Battery Storage and Microgrid often include distributed generation and storage technologies as well as load-modification practices. While most battery storage and microgrid projects around the country have been driven by mandates or R&D efforts alone, Duke Energy has proactively evaluated these technologies and led multiple projects and plans that incorporate these non-wire alternatives. The primary applications for battery storage and migrogrid deployments can range from enhancing reliability to a community through local generators to increasing capacity to new customer loads or EV charging stations, for example, through local storage assets.

As discussed throughout this Plan, Microgrids typically integrate solar PV, battery storage, and other distributed energy technologies with the capability of isolating customer loads from the grid. The Mt. Sterling Microgrid, approved by the Commission and constructed in 2017, is currently serving a remote customer in a more reliable and cost-effective way than a traditional distribution feeder while also enhancing employee safety and productivity by mitigating O&M activity in a high-risk, labor-intensive environment. Similar opportunities to deploy renewable-based Microgrids will be considered when warranted by the cost of serving customers in a traditional manner from the distribution grid, customer demand, or other situations where reliability of service is critical.

The Company's latest IRP also outlines the many steps the Company is taking to further its commitment to non-wire alternatives like renewables and battery storage by working with utility customers on innovative and sustainable solutions while diversifying the Company's regulated generation, transmission, and distribution systems in a cost-effective manner.

5. Pilot Projects and Initiatives

Reference	Requirement
R8-60.1 (c) 5	*For each pilot project or initiative currently underway or planned within the next two years to evaluate smart grid technologies: (i) – (v)*

Physical & Cyber Security

Device Entry Alert System (DEAS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objective of the Device Entry Alert System (DEAS) project is to install an entry door alarm head-end system and processes for tracking and monitoring physical access of distribution line device field Intelligent Electronic Devices (IED) devices and related infrastructure.

The current solution concept, still under review, will likely include:

- Addition of entry alarms to distribution line device panel doors that will activate when the door is opened (e.g. recloser)
- A system that integrates with the field device entry alarms, receives a notification when it is activated and pairs it with a virtual logging system
- A means of distinguishing between authorized and unauthorized entries, all notifications being logged and reported
- A means of autonomously "blacklisting" or limit communications with field cellular modem.
- Includes the development of the business processes related to the system monitoring and response

The concept, similar to the process utilized for Transmission substation entry, is focused on distributed equipment across the Duke Energy footprint

(ii) The status and timeframe for completion.

The in-service and completion date is still to be determined.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

$ in millions	actual	Jan-Jul	Aug-Dec	estimate	estimate	estimate	estimate

		actual	estimate				
Project	2017	2018	2018	2019	2020	2021	2022
DEAS	0.000	0.000	0.000	0.756	0.181	0.000	0.000

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

The initiative is still in the planning stages.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The initiative is still in the planning stages.

Distribution System Modernization, Automation and Intelligence

Sectionalizing Device with remote monitoring and control

(i) A description, including its objective and an explanation of how it will improve grid performance or provide improved or additional utility goods and services.

The Hydraulic Recloser Replacement Program is an enterprise wide effort to phase out oil-filled reclosers and replace them with solid dielectric sectionalizing devices with remote monitoring and control. This will provide a means by which to reduce Duke Energy’s oil footprint and eliminate maintenance activities required for upkeep of the existing oil-filled fleet. This transition will be a phased approach to allow for the depletion of existing oil-filled inventory. Hydraulic reclosers have been separated into two categories by size: 140A and greater and 100A and less. Units 140A and greater are being replaced by the standard Duke Energy electronic line recloser. A replacement has not been finalized for units 100A and smaller which is the focus of this initiative.

(ii) The status and timeframe for completion.

An RFI was issued to multiple vendors in this space and alternative solutions are currently being evaluated. A solution is needed by 2020 when existing inventories of reclosers are depleted.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The project was not funded by government grants. A proof of concept is being developed to refine both the technical approach, cost and the business processes required.

actual | Jan-Jul actual | Aug-Dec estimate | estimate | estimate | estimate | estimate

Project	2017	2018	2018	2019	2020	2021	2022
Proof-of-Concept	0.000	0.000	0.000	TBD			
Total							

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

A proof of concept on the small electronic sectionalizing device with remote monitoring and control capability was conducted in which a cut-out mounted sectionalizing device was evaluated with a communications gateway. The proof of concept was unsuccessful and this solution was removed from consideration.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The cut-out mounted sectionalizing device with remote monitoring and control capability proof of concept was not successful due to the fact that the communications gateway did not provide remote configuration management or remote firmware management of either the recloser units or the gateway itself. Also, the promised SCADA functionality (remote control and monitoring capability) did not work. The communications gateway would not connect to the Duke Energy DSCADA system.

Additional proofs of concept are planned for 2019 to evaluate the options presented through the previous RFI effort. The scope includes installation of a 3PH site and 1PH site to fully evaluate the capabilities of vendor offerings in the small electronic sectionalizing device with remote monitoring and control capability space.

Distributed Intelligence (Utility Internet of Things) Proof of Concept

(i) A description, including its objective and an explanation of how it will improve grid performance or provide improved or additional utility goods and services.

Duke Energy recognizes the need to have an agile and adaptive grid with the ability to be able integrate growing amounts of DER (Distributed Energy Resources), storage, promoting enhanced segmentation, two-way power flows, voltage support, and other capability enhancements over time. The ability to provide this agile and adaptive grid requires the capability to utilize and manage low latency communications and allow for rapid decision making as distributed resources and a more agile system will likely experience greater cyclical changes related to voltage and the direction of power flows. The goal is to utilize a proof of concept to allow for the further development and evaluation of distributed communications and computing platform that will support some of the following capabilities while supplementing Duke Energy's investments in enhancements to its central advanced distribution management system (ADMS).

Initial use cases to be investigated:

- Voltage Management and Optimization capability use cases to be explored:
    - Use Case - DER Circuit Segment Management
    - Use Case - Solar Smoothing with PV and Advanced Inverter
    - Use Case – Solar Smoothing with PV, Advanced Inverter, and Battery
    - Use Case – Volt/VAR Management
- Additional related capability use cases to be explored:
    - Use Case - Inadvertent Island Detection
    - Use Case - Localized Protection Alarms and Events
    - Use Case - Remote Device Configuration
    - Use Case - SCADA Point Aggregation
- Develop, deploy, and evaluate the potential complementary benefits that DI can provide with DER integration, including enhanced ability to manage voltage, with Duke's ADMS strategy
- Several key aspects of this work will cover the following categories of scope:
    - Telecom capability, including peer to peer communications and low latency data bus capabilities
    - Cyber and Physical Security Segmentation and Application
    - Multi-vendor intelligence device integration and standardized control layer protocol application development

(ii) The status and timeframe for completion.

The initial focus is on capability planning, to be followed during the 2019-2021 timeframe with an initial proof of concept on voltage support capabilities related to storage and DER integration on the distribution system. Following a successful completion of a proof of concept in 2021, a pre-scale with a focus on enabling additional use case capabilities that allow for edge and low latency decision making to occur will be pursued from 2021 through 2022 to further evaluate capabilities.

(iii)The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The project will not be funded by government grants.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Proof-of-Concept	0.000	0.000	0.000	2.025	1.000	0.900	
Pre-Scale							0.750

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

Not yet complete

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

Not yet complete

Customer Programs

Smart Meter Usage App

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The company has been evaluating offering a potential enhancement to its residential My Home Energy Report Program (MyHER). This offering, previously referred to as the Smart Meter Usage App, has been branded internally as My Home Energy View (MYHEV). Similar to the existing MYHER program which has leveraged a customer's monthly billing data, the new offering will leverage the ability of the new AMI meters to provide interval usage data in hope of engaging, motivating and empowering customers to become more energy efficient. My Home Energy View is designed to give enhanced convenience and transparency to a customer regarding their electric energy usage patterns. This program installs a device in a customer's home that is capable of reading actual usage data from the smart meter in near real time and then communicates with an App on the customers phone via the customer's Wi-Fi. For this program, the extremely granular usage data is not provided back to the Company, it is only leveraged by the customer. By leveraging the app (provided to the customer) the customer can see real time usage and potentially the disaggregated view of their consumption (i.e. what applications in their home are consuming, broken down by the appliance – HVAC, refrigerator, base load, etc.).

Penetration testing has been completed for this technology and it met the required standards for compatibility with the AMI meters. Our next step is to pursue approval from IT Security.

The vendor states the expected life of the technology is 7-10 years, given the historical stability of the protocols they are supporting.

Finally, the Company needs to assess the program enhancement cost effectiveness to determine its feasibility to become a full-scale customer offering.

(ii) The status and timeframe for completion.

The Company is waiting for management approval to rollout the pilot. Pending approval, the pilot rollout would occur Q4 2019.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The Company has incurred $1,598,231 to date investigating and evaluating this potential energy efficiency program enhancement.

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

A customer pilot has not yet been initiated so results are not available at this time.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The results of the planned pilot will help the company determine how to offer the program at scale, the expected participation rate, and the necessary regulatory filings.

Prepaid Advantage

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Prepaid Advantage is a payment option that broadens the portfolio of Enhanced Customer Solutions and payment options. Prepaid is a purely voluntary option.

The Company is currently offering a pilot of Prepaid Advantage to a cap of 4,000 customers in DEC South Carolina. To inform future offerings and or expansion of the Pilot, Duke Energy is seeking to 1) validate that the Prepaid Advantage technology and data exchanges work as designed and meet the needs of customers; 2) measure and track participant data, behavior and satisfaction to evaluate the need and feasibility to expand the Program; and 3) Test the Program's overall ability to give customers the choice, control, and flexibility to pay, in real time, for electricity.

The Pilot is designed to give customers the control and flexibility to make payments to their account before using electricity. The amount one pays determines how much electricity one can use. The technology used for the Pilot will enable residential customers to see their electric consumption on a daily basis and monthly basis. Customers will be able to view usage and account balance information on a web portal (via desktop or Smartphone), and receive alerts through text messages, e-mail, and automated outbound calls, at their discretion. Customers will be able to use this information to recognize higher than usual electricity consumption on a daily basis, thereby better understanding what drives their costs. Furthermore, Prepaid provides residential customers with greater payment flexibility, allowing frequent cash payments which may help customers better manage their finances. Prepayment does not require a deposit fee, allowing customers to use funds to which they otherwise would not have access.

(ii) The status and timeframe for completion.

The Company is considering launching Prepaid Advantage for DEC North Carolina. More definite next steps will be confirmed in Q4, 2018.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

To date, the Company has incurred approximately $550,000 to build, market and operate the South Carolina Pilot. Once the Program is launched for DEC and DEP North Carolina, the Company is unlikely to incur additional implementation costs. No costs have been incurred to date in DEC North Carolina.

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

For the South Carolina Pilot, approximately 2,800 customers are enrolled today. Comprehensive results will be available following the completion of the Pilot. No results are available for North Carolina as the Program is not currently offered there.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The results of the planned pilot will help inform future offerings or expansion of the Pilot. The following data is being collected:

- Number of payments per month and average payment amount per customer;
- Number of nonpayment disconnects and reconnects;
- Customer energy usage patterns;
- Customer satisfaction; and
- Number of customers who choose to withdraw from the Pilot (other than move-outs) and the reason for withdrawal.

Emerging Technology Trends (ETO)

The Emerging Technology Office's (ETO) mission is to lead Duke Energy in the identification, evaluation, development, and application of emerging technologies - technologies that may not be ready for wide-scale deployment for another 3-10 years; to identify related business opportunities and risks; and to transfer technologies to the business units to optimize value in a dynamic technology, customer, and regulatory environment. Some technologies and trends may be evaluated and deemed non-viable or non-transferable. The ETO is continuing to evaluate emerging technologies such as battery storage, microgrids, and other grid-related technologies as listed below.

Microgrid Pilots

The US Department of Energy defines a microgrid as a group of interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid is able to connect and disconnect from the grid to enable it to operate in both grid-connected or island-modes. Microgrids owned and operated by Duke Energy enhance resiliency, improve reliability, and deliver economic and environmental benefits to participating and non-participating customers. Non-participating customers will benefit from increased reliability to critical service facilities, emergency services, and/or other public purposes served by a microgrid. In addition, to the extent a microgrid is able to provide support to the grid, all customers benefit.

Integrating advanced protection and control technologies with DER in a microgrid supports the rapid operation of automated devices in response to an outage or power quality issue. Ultimately, this enhances the resiliency and reliability of customer electric supply. During a regional outage event, power generated by renewable technologies cannot be transmitted to the grid; the standard operating procedure is to isolate the assets. Microgrid technologies, however, allow the renewable assets and other DER within the microgrid to continue generating power for participating customers. Through multiple pilot projects and partnerships, Duke Energy is testing various microgrid control modes to evaluate and demonstrate how microgrids will automatically respond to and re-synch to the grid following outages. Current pilot projects include the McAlpine microgrid in South Charlotte and the Coalition of the Willing microgrid in Mount Holly.

McAlpine Microgrid

The McAlpine Microgrid was commissioned in late 2015 and continues to provide insight into the operational requirements of a microgrid on the utility system. Earlier in 2016, the microgrid successfully responded to a system disturbance and seamlessly transitioned the customer (Fire Station 24) from the grid, to the microgrid, and a return to the grid.

In the spring of 2016 a long-duration islanding test was developed and executed. The duration test was deemed a necessity to determine the performance of the microgrid components operating in a long-term island scenario. Testing also was required to fully understand the Auxiliary Power requirements needed to operate the network equipment, air conditioning, lighting etc. installed as part of the microgrid. The HVAC system in the Battery Energy Storage System required a change out during 2016 at a cost of approximately $15k.

The duration test proved that successful long-term support of Fire Station 24 can be provided by the battery energy storage system and solar. The microgrid controller performed very well, and managed the state-of-charge of the battery during periods of excess solar energy production by cycling the solar as needed. However, the performance of the battery was not as expected with the energy provided falling far short of expectations. Based on analysis of the data from the test, auxiliary power requirements consumed a large part of the energy needed to run the microgrid. The results of this test are already being used in other energy storage assessments, and are being used in industry forums and vendor meetings to influence the future direction of auxiliary and standby power requirements for energy storage systems.

Mount Holly Microgrid

Building off of the successes of The Coalition of the Willing work (Phase I and Phase II) and the growing industry acceptance of the Open Field Message Bus (OpenFMB™), the Mount Holly Microgrid is positioned as one of the most advanced microgrids in the country. Upgrades to the original microgrid were designed and are being continuously implemented to research new areas of interest. The heart of the microgrid is the 650kW/326kWH Saft Li-ion battery installed in 2017. The battery runs in voltage source mode continuously which provides the microgrid, when islanded off of the Duke Energy grid, the voltage and frequency support it needs. The brains of the Mount Holly Microgrid is a Schweitzer Engineering Laboratory Real-Time Automation Controller which is installed in the new 4-way islanding switch from G&W Electric. This combination allows for seamless islanding and reconnection to Duke Energy's grid. The standard operating mode for the microgrid is islanded. The integration of 150kW of solar panels and the Saft battery allow the microgrids load to be disconnected from the grid for a majority of the day. The only times that the Mount Holly Microgrid connects back into the Duke Energy grid is to charge the battery. This generally happens late at night or if clouds prevent the solar array from producing power to charge the battery during the day. The upgrades to the Mount Holly Microgrid cost $1.4M which includes material, labor and integration costs.

This work has continued to advance Duke Energy's knowledge base around microgrids and the need for more distributed intelligence and interoperability between devices in the grid. The ETO is continuing to transfer lessons learned around our work to other Duke Energy business units to provide valuable outcomes for our customers. Further work is ongoing at Mount Holly to expand the use of OpenFMB to easily integrate DER devices into the microgrid. In 2018 and early 2019, a new 500kW natural gas generator will be installed to provide additional functionality to the Mount Holly Microgrid. The use case being researched is to better understand how a customer with existing generation may implement a microgrid. This generator represents the first rotating mass generation device on the Mount Holly Microgrid. The project cost to install the generator on the microgrid is $650k. This price includes the generator, the gas line extension to the site, and all of the interconnection work involved in getting it connect to the existing microgrid.

The Emerging Technology Office is analyzing all the results from the installation and operation of the microgrid to evaluate technical, operational, and financial benefits for customers and the utility. The goal is to potentially offer new products and or services to customers to assist them in meeting their evolving energy needs.

Rankin Circuit

As an important next step and logical extension to the Coalition of the Willing phase II project, a field test of the same interoperability concept will be conducted at the Rankin circuit on which the Mount Holly microgrid resides. The Rankin circuit test, which is on track to become Duke Energy's second reference implementation of the OpenFMB™ standard, will include the active coordination of the DER devices within the Mount Holly microgrid, a substation battery system, distribution automation devices, and a 1.2MW of solar at the end of the circuit. Similar to the OpenFMB™ microgrid facility at Mount

Holly, the Rankin circuit will leverage the industry standards stakeholder community at the Smart Grid Interoperability Panel (SGIP) for the definition and consensus on the operational use-case – DER circuit segment management – to be employed at this test site with the intent to demonstrate how distributed intelligence can help enable multiple functions that lead to stacked benefits. Prior to its implementation on the Rankin circuit, a variety of scenarios of this foundational use-case will be developed and validated inside the Mount Holly lab using real-time simulation creating a digital twin of the circuit. ETO personnel and UNCC EPIC students are designing this hardware in the loop (HIL) simulation. Started in 2017 and continuing throughout 2018, there will be approximately $750k spent on this work. Furthermore, the Rankin circuit model will become the baseline validation instrument for new emerging use-cases to be developed and simulated before future operational pilot testing on Duke Energy power system and telecommunications infrastructure in 2019 and beyond.

Energy Storage Pilots

Distributed energy storage continues to gain momentum as a viable solution as the price of batteries continues to drop and utility operators experience more installations on the system. The Company is continuing to evaluate additional storage opportunities with various chemistries across multiple use cases. Batteries offer flexibility by being able to perform a multitude of functions. Distributed batteries have the ability to offer capacity, spinning reserves, solar and wind smoothing, loss reduction, outage ride-through and other system benefits. In addition to the projects discussed in previous filings, Duke Energy continues to evaluate and demonstrate these many capabilities at different points on the grid.

For 2018 a directional shift was made to evaluate “non-lithium” technologies. This shift was made due to several factors:

1) Lithium Ion battery technology is commercially available in the marketplace and its performance is well understood.
2) Multiple vendors have approached Duke Energy ETO with super capacitor and aqueous hybrid type energy storage technologies. The large number of these vendors shows promise that some of these technologies will be successful.

<u>Distributed Energy Storage Projects in the Carolinas</u>
Several projects are in the planning and development stages at present, with field installations expected to be completed in 2018 and 2019, as listed below:

<u>Rankin Hybrid Energy Storage</u>
Located at the Rankin substation in North Carolina, the project originally tested a 402-kilowatt (kW) battery linked with a commercial solar installation located 3 miles away. The original solution testing was completed in 2015, and a new hybrid distributed storage solution was installed in the first quarter of 2016. This novel solution pairs two storage technologies from different vendors - a high energy battery solution from one vendor, with a high-power capacitor solution from the other vendor. Total system rating is approximately 370 kW and 600 kWh. The objective of this project was to understand

the potential of hybrid battery solutions to improve the performance, life-cycle, and cost of energy storage solutions. This is also the first time that multiple storage solutions have been installed by Duke Energy with a common DC bus and shared inverter. This project uncovered a multitude of issues and nuances in the control and dispatch of energy storage assets connected on a DC bus. The main issues that arose during this project involved the requirements for fast and deterministic controls between the DC/DC converter and inverter. Because the original vendor did not properly design the control system these communications and the overall control scheme was determined to be unusable long term. This project brought to light the real-world issues the industry still faces in real time controls and was a great learning point for how we will specify future systems.

Emerging Technologies still believes there is high potential for ultra-capacitors to provide better high power, short duration impact for solar intermittency and voltage sag mitigation. It was therefore determined that a retrofit of the existing hybrid energy storage system would be required to fully understand the potential of the ultracapacitor technology. Between 2018-2019 Emerging Technologies will be retrofitting the existing site with a new Ultracapacitor system built specifically for utility applications. This system will also utilize a more robust inverter architecture, built for system resiliency, and remove the interconnection of another battery on the DC bus.

The retrofit project will leverage the infrastructure of the previous Rankin storage device, as well as in-kind contributions from multiple vendors. Duke Energy will invest approximately $500k, approximately half of the total installed cost of the retrofit system.

Marshall Energy Storage

The currently installed 1.2 MW solar and 250 kW Energy Storage System at this site are being utilized to develop algorithms to manage distribution-tied DER integration. The work is being developed and tested in partnership with UNC-Charlotte's EPIC Center. Self-learning forecasting routines will incorporate weather, circuit and usage data to best determine how to operate DER at different times of the day and seasons to offset voltage rises on the circuit and fluctuations due to solar intermittency and to reduce voltage regulator operations.

Duke Energy has invested $115k in 2015 and $137k in 2016 in the development of the algorithm software and readying the software for installation at the Rankin circuit in Mt. Holly to test the "self-learning" capabilities that may be required in the future.

The Marshall energy storage site is located on the coal ash fill at the Marshall generation plant site. Due to the new requirements related to working at a coal-ash location, additional testing at the Marshall energy storage site will be reduced in the future. Consideration will be given to removal of this test bed, but a final decision has not been made.

ETO is currently evaluating repurposing of the Marshall energy storage site to allow testing of the Regulated Business Energy Storage Control system to be deployed on the 2019 Regulated Energy Storage projects. ETO has spent $6K to have the S&C Inverter serviced at the site. A request has been made to Kokam to provide a quotation to have the Kokam battery serviced. We are awaiting the quotation for that service. If testing moves forward total 2018 spend will be $20K-$30K.

McAlpine Solar DC Coupled Energy Storage

Located at the McAlpine Creek Substation is a 50 kW solar field that is part of the regulated solar generation fleet. Duke Energy has entered into contract with EOS Energy Storage to test their Zynth energy storage technology in a DC coupled arrangement with the solar. DC coupled energy storage and solar proposes to provide efficiencies to capture clipped energy and shoulder energy that would be wasted without the energy storage ability to capture it. This energy would be discharged into the grid to help offset the duck curve in the evening.

The EOS Energy Storage Zynth technology offers several advantages over lithium ion based energy storage:

1) Does not require active air conditioning
2) Is non-hazardous and chemically safe. Can be shipped without hazardous handling.
3) Will not burn
4) Can be charged and discharged from 100% to 0%. All energy in battery can be used.

The project is being designed in Q2-Q3 2018 and construction will begin in Q4 2018. The EOS battery will be delivered in Q1 2019 with full operation expected in Q2 2019. An 18-month test period has been designated with complete reports for intended use cases as the deliverable. Total expenditure is $275K with a 2018 spend of $100K.

Kilowatt Labs Super Capacitor Evaluation

Kilowatt Labs is a manufacturer of super capacitor based energy storage systems for the small and medium commercial and industrial marketplace. Kilowatt Labs claims that their Sirius Energy Server technology which manages the charge of the super capacitors will allow energy capacity of the super capacitors to be roughly 4 times that of rival systems. Combined with the short duration charge and discharge times and the very high number of charge and discharge cycles make the technology attractive for high cycle applications. ETO will take delivery of a test system at the Mount Holly test lab in Q3 2018 with an operational date of Q4 2018. Total expenditure for the project is estimated at $30K.

Tesla PowerPack 2 Energy Storage System

In 2016 Emerging Technologies decommissioned an ATL battery that was initially part of the Mt Holly microgrid due to constant issues with thermal management, limiting the overall energy the battery system could provide. A Tesla PowerPack 2 energy storage system was selected as a replacement to be installed in 2018. The system will interconnect to the existing microgrid, utilizing infrastructure installed for the original ATL battery. This energy storage system will be used in current source to supply power to the islanded building when not connected to the grid. This system will also be commissioned to operate as a voltage source for the microgrid in the event of failure of the existing Saft energy storage system. This high availability design could be a potential customer offering in future microgrid projects. In grid connected mode the Tesla battery will be utilized to balance real time power flow to ensure that no power is exported out of the microgrid.

The total project cost for this system is approximately $500k, with Tesla giving Duke Energy special pricing consideration due to the research nature of this project. Duke Energy will be able to leverage existing assets to further reduce the costs of installation.

Residential Energy Storage (RES)

Commercially available battery solutions are emerging for residential applications. In principle, multiple customer-sited battery solutions could be aggregated to provide benefits to the electric grid, as well as short duration back-up power to customers. Emerging Technologies installed 3 separate residential energy storage installations at the Mt Holly Microgrid Innovation Center to test capabilities and get a better understanding of the total install cost and maintenance requirements.

Approximately $50k was invested by Duke Energy to investigate the three-separate residential energy storage installations. Installation costs ended up being approximately half of the total install costs for these systems, much larger than anticipated. Issues arose when using an inverter manufacturer that was different than the battery manufacturer in one of the installations, leading Emerging Technologies to recommend that any future program only contain one point of contact for behind-the-meter energy storage solutions. Overall the installations were technically successful, but it became clear that residential energy storage vendors have the mindset that these systems will be purchased and operated by home owners and not utilities. Due to this there are limited value propositions for utility applications with current iterations of these systems. The main value proposition to customers in Duke Energy's service territory was determined to just be backup power, while the utility can take advantage of demand response applications.

Pika Energy Storage

The Pika Energy Island is being installed for testing and evaluation at the Mount Holly test lab in 2018. The Pika Energy Island is a full microgrid system with energy storage, solar and smart inverter technology combined. The technology is unique in that it provides the ability to balance the energy storage, solar energy output and customer so that the grid supply is net zero. Neither importing nor exporting any energy from/to the grid when commanded to. This functionality may be of interest to Duke Energy in the future as more residential energy storage and solar is deployed. Expenditure for the testing in 2018 is $30K.

Zero Net Energy Homes

Advances in residential home construction have improved home performance substantially over the last decade. Additionally in the past few years, more and more new homes are being equipped with solar and smart home features as builders compete on connectivity, customer convenience and operational cost. An end result of the combination of these technologies can lead to Zero Net Energy Homes – homes that are very energy efficient and produce enough onsite generation to completely offset their load on an annual basis. The building-in of energy efficiency and smart home features, also provides greater capability for these homes to contribute to balancing and operation of a more flexible and changing grid but only when operated with utility's needs in mind. To this end Duke Energy has partnered with Meritage homes and EPRI to build 6 homes across Florida and North Carolina to understand how customer energy efficiency, home automation and distributed generation can be used for both the customer and utilities benefit. Technologies being investigated in these homes are: solar, high thermal mass insulation, heat pump water heaters, energy storage and conditioned attic space. This project is expected to provide the public and utilities a much better insight into how advanced construction techniques and new connected customer technologies could enable grid balancing.

To complete this project Duke Energy invested approximately $125,000 with a significant portion of the research funding coming from EPRI. The homes will be completed in 2018 and then post occupancy analysis will take place to determine best optimization of the different technologies to ensure utility system benefit and occupant comfort and convenience.

6. Projects No Longer Being Considered

Reference	Requirement
R8-60.1 (c) 6	*A description of each project or initiative described in a previous plan that is no longer under consideration by the utility, and the basis for the decision to end consideration of each project or initiative.*

At this time, the Company does not have any project or initiatives previously reported that are now no longer being considered.

7. Advanced Metering Infrastructure (AMI) Summary

The responses included within this section are submitted pursuant to NCUC Rule R8-60.1(c). On June 22, 2018, the Commission issued an Order Approving Manually Read Meter Rider with Modifications and Requesting Meter-Related Information in Docket Nos. E-7 Sub 1115, E-100 Sub 147, and E-100 Sub 153 which directed DEC to include additional information in the SGTP. In accordance with this Order, DEC submits the following exhibits: Verified Statement Regarding the Usage of Customer-Related Data and Security Procedures (attached as Exhibit A), Smart Meter Incident and Cyber Security Risk Report (attached as Exhibit B), and Opt-Out Report (attached as Exhibit C).

Reference	Requirement
R8-60.1 (c) 7	*For automated metering infrastructure (AMI), in addition to the information required in subsections (3) or (4) of this section, as appropriate, the utility shall also provide: (i) – (iv)*

(i) A table indicating the extent to which AMI meters have been installed in the utility's service territory and specifically in North Carolina, the North Carolina jurisdictional customer classes and/or tariffs of customers with AMI, and the predicted lifespans of these installations. This table should indicate the number of AMI meters that has been installed both cumulatively and since the filing of the last smart grid technology plan.
(ii) The number of meters in North Carolina that use traditional metering technology and/or automated meter reading (AMR) technology, and the predicted lifespans for these installations.

Meters installed in DEC North Carolina as of August 2018

Customer Class	AMI Meters	AMR Meters	Walk-By & Other Meters
NC Residential	1,484,422	263,251	1,556
NC Commercial	241,383	38,251	3,979
NC Industrial	4,217	73	849
NC Company Use & Other	0	0	0
Totals	**1,730,022**	**301,575**	**6,384**

DEC has installed approximately 318,397 smart meters in NC since the information provided in the 2017 Smart Grid Technology Plan Update. The AMR meters are being recovered over a period of 15 years and the smart meters will be depreciated over a period of 15 years pursuant to the terms set forth in the Company's last rate case proceeding Order entered June 22, 2018 in Docket No. E-7, Sub 1146.

(iii) Any adjustment made by the utility to its capital accounting due to AMI, including the dollar amount of write-downs of its meter inventories.

In the Commission Order in Docket No. E-7, Sub 1146 dated June 22, 2018, the Commission approved a 15 year depreciation life for new AMI meters. The remaining book value of the AMR meters replaced in the scope of this project will be depreciated over a 15-year period. In DEC North Carolina, the remaining book value of meters being retired through the AMI deployment is being deferred in a deferred debit account pending Commission approval in Docket No. E-7, Sub 1146 for the Company's request to include the amount for retired meters in a regulatory asset.

(iv) A discussion of what AMI services or functions are currently being utilized, as well as any plans for implementing other AMI services or functions within the next two years.

DEC is currently utilizing the remote meter reading functionality of the AMI meters, replacing walk-by and drive-by meter reading. Along with the usage reading, the AMI meters also provide enhanced detection of meter tampering as well as voltage and reactive power measurements. DEC is also utilizing the remote order fulfillment capabilities of the meters, allowing for remote off-cycle reads or re-reads, remote reconnections and disconnections, and read-in/read-out orders to stop or start service.

For customers with an AMI meter, DEC also provides the ability to access day prior electric usage information via the internet-based Customer Portal. The Portal displays usage information up to and including prior day usage. Customers can view daily and average energy usage by billing cycle or month. Customers can also view average energy usage by day-of-week, and hourly energy usage by day or week, including average temperature data. Usage data is available for the previous 13 months, or as of the AMI meter certification date. Time-of-Use and Demand customers are able to view the information above, and can also see the date and hour when the peak usage or peak demand occurred, for the current or selected billing cycle. Customers also have the ability to download their hourly usage data from the Customer Portal in a .CSV format.

The customer programs enabled by the AMI meters that are currently being deployed or scheduled for implementation within the next five years include Usage Alerts, Pick Your Due Date, and Outage Notifications. These programs are discussed in detail in Section 3 above. Pilot programs planned within the next two years include the Smart Meter Usage App and Prepaid Advantage and are outlined in Section 5 above.

Pursuant to the terms of the North Carolina Utilities Commission's March 7, 2018 *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data* (March 7, 2018 SGTP Order) in Docket No. E-100, Sub 147, Duke Energy has convened meetings with the NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data. See SGTP Exhibit 2 for additional information related to these meetings.

Appendix A – Verified Statement Regarding the Usage of Customer-Related Data

2018 Smart Grid Technology Plan of Duke Energy Carolinas, LLC
Appendix A to Section 7
Docket No. E-100, Sub 157

I, Sasha Weintraub, being first duly sworn, deposes and says:

I am an officer of Duke Energy Carolinas, LLC, (DEC or the Company) employed as Senior Vice President, Customer Solutions. The Company uses customer-related smart meter data to give our customers greater convenience, control and transparency over a customer's energy consumption. The customer's kWh usage is utilized for billing and usage alerts and to provide customers information regarding their hourly and data usage patterns. It may also used to provide additional billing options, such as Pick Your Due Date, Time of Use, and Prepaid Advantage. The Company uses customer-related smart meter data to collect meter tampering information for safety and security. The Company uses voltage information to detect customer power quality issues, determine meter mapping characteristics, and for troubleshooting other field issues.

The Company has multiple procedures to keep customer-related smart meter data secure and to protect customer privacy. Smart Meter Data is collected and transported over a network that utilizes Advanced Encryption Standard (AES) encryption, ensuring the privacy of the data during transport. Smart Meter Data that is stored in our Meter Data Management system is protected by authentication processes which ensure access to the data is limited to only authorized individuals with a valid business need have access to this data. There are also Sarbanes-Oxley controls in place to ensure compliance to our security standards, which includes but is not limited to: audited security access approval processes, periodic auditing of access, and database monitoring tools that will monitor and alert for any suspected un-approved access to the data. Duke Energy maintains a Data Privacy Policy (attached hereto as Appendix 1) that establishes an internal Data Privacy Program. The Data Privacy Program is designed to ensure proper control, reasonable to the size and complexity of the function/business, regarding the protection of information, pertaining to an individual, which is collected through normal business operations. The Policy is designed to support Duke Energy's business functions. The requirements of the Data Privacy Program are explained in the Data Privacy and Identity Theft Protection Standard (attached hereto as Appendix 2). The Standard establishes requirements to ensure consistent measures are implemented to protect Duke Energy, its workforce, customers, shareholders, and other third parties with which it does business from unlawful disclosure or transmission of Personal Information.

Additionally, Duke Energy has a public web Privacy Policy posted on the www.duke-energy.com Internet page, available at http://www.duke-energy.com/privacy.asp. This Policy is customer facing and sets forth how Duke Energy collects, uses, and protects and uses customer information received online.

Dated this, the 25 day of September, 2018.

Nyfin (Sasha) Weintraub

Sasha Weintraub, SVP, Customer Solutions
Duke Energy Corporation

Subscribed and sworn to me this
25 day of September 2018
Carla Sechrest
Carla Sechrest
Notary Public for North Carolina

My Commission Expires: 7/27/2019

CARLA SECHREST
Notary Public
Rowan County
NORTH CAROLINA

Duke Energy Policy

Data Privacy Policy

Applicability:	Enterprise
Originator:	Corporate Compliance
Approval:	Chief Compliance Officer
Effective Date:	10/01/2006
Revision Date:	06/26/2013
Revision No:	3

Statement of Purpose and Philosophy:

Duke Energy intends to comply with applicable federal, state, and local laws, regulations, ordinances, and internal policies, including, but not limited to, the Code of Business Ethics (all collectively referred to as "Rules") including those that protect information regarding an individual from unlawful disclosure or transmission. Failure to do so may result in legal penalties, adverse regulatory action, restriction or prohibition from conducting business with certain countries and irreparable damage to Duke Energy's brand.

Scope:

This policy is applicable to all workforce of the new Duke Energy located within the United States. Employees and agents of Duke Energy located outside the United States should refer to their in-country legal counsel and compliance personnel for data privacy requirements at their locations.

1. Policy Expectations

This policy establishes requirements regarding the protection of information about an individual in a manner consistent with the applicable Rules. This policy is designed to support Duke Energy's business functions as Duke Energy seeks to be a leader in considering and addressing privacy-related concerns of individuals.

2. Roles and Responsibilities

Chief Compliance Officer will be responsible for:

- Establishing and providing oversight for a Data Privacy Program to ensure adequate policy and standards are implemented to reasonably ensure compliance with Rules that are applicable to Duke Energy regarding information about individuals.

Functional/business units will be responsible for:

- Ensuring that the expectations of this policy are achieved for their respective function/business unit and that the applicable processes or mechanisms are sustained.

The workforce will be responsible for:

- Ensuring their daily practices comply with this policy.

Data Privacy Policy

- Considering and addressing privacy-related concerns associated with any information about an individual within their possession and/or control.
- Reporting privacy-related concerns appropriately and in a timely manner.

3. Definitions/Key Terms:

Data Privacy Program: Duke Energy's governance model that will ensure proper control, reasonable to the size and complexity of the function/business, regarding the protection of information, pertaining to an individual, which is collected through normal business operations. The Program is established by this policy. The Data Privacy and Identity Theft Protection Standard is the supplemental document that explains the requirements of the Program.

4. Related Documents

Web Privacy Policy
Data Privacy and Identity Theft Protection Standard
IT 200 Information Technology Asset Management Policy
IT 201 Information Management Standard
IT 500 Cyber Security Policy
Purchasing Controls Policy

Data Privacy and Identity Theft Protection Standard

Applicability:	Enterprise
Originator:	Corporate Compliance
Approval:	Chief Compliance Officer
Effective Date:	08/01/2009
Revision Date:	08/15/2017
Revision No:	6

Scope

Compliance with this Data Privacy and Identity Theft Protection Standard ("Standard") is the responsibility of the Duke Energy workforce performing work or services for, or on behalf of, Duke Energy who process Personal Information.

The Duke Energy workforce performing work or services for, or on behalf of, Duke Energy outside of the United States should refer to their in-country legal counsel and compliance personnel for data privacy and identity theft protection standards requirements at their locations.

Statement of Purpose

This Standard defines the requirements under the Data Privacy Program established in the Data Privacy Policy. The requirements will ensure consistent measures are implemented to protect Duke Energy, its workforce, customers, shareholders and other third parties with which it does business from unlawful disclosure or transmission of Personal Information.

Note: The respective state utility commissions may establish requirements in regard to Customer Information that are not included in the scope of this Standard regarding Personal Information. Those requirements are listed in the respective links below. In addition, the Clearinghouse document explains the enterprise process to manage requests to use Customer Information.

North and South Carolina:
https://www.duke-energy.com/_/media/pdfs/legal/duke-piedmont-code-of-conduct.pdf?la=en
Ohio: http://codes.ohio.gov/orc/4928.17
Kentucky: http://www.lrc.ky.gov/KRS/278-00/2213.PDF
Indiana: https://www.duke-energy.com/_/media/pdfs/legal/de-in-affiliate-standards.pdf?la=en
Florida: Rule No. 25-6.014 and Rule No. 25-6.015
Clearinghouse: Customer Data Request Form

Related Documents

Data Privacy Policy
Web Privacy Policy
Guidelines for Protecting Personal Information
IT 200 Information Technology Asset Management
IT 201 Information Management Standard
IT 500 Cyber Security Policy
IT 501 Cybersecurity Standard

Glossary of Terms

Breach – any substantiated Exposure that requires notification under State data privacy laws to impacted individual(s) generally due to the reasonably likely risk of identity theft or identity fraud, or that creates a material risk of harm to the impacted individual(s).

Customer Information (CI) – Nonpublic smart or legacy data that can be used to identify a Customer or a group of Customers, including but not limited to electricity or natural gas consumption otherwise known as energy usage information, load profile, billing history, credit history, survey responses or other research and analysis that is or has been obtained or compiled by Duke Energy in connection with supplying electric or natural gas services.

Data Privacy Program – Duke Energy's governance model that will ensure proper control, reasonable to the size and complexity of the function/business, regarding the protection of information collected through normal business operations that pertains to an individual.

Data Sponsor – The manager responsible for maintaining the confidentiality, integrity and availability of company information within his/her business unit per the IT Glossary referred to in IT 200 – Information Technology Asset Management Policy.

Exposure – Any event, disclosure or transmission that has allowed any group(s) or individual(s) to obtain, or potentially obtain, access to Personal Information without a legitimate business reason.

Identity theft or identity fraud – A crime committed when a person uses another person's Personal Information without authorization to commit fraud.

Information Owner – The Information Owner is accountable for one or more information systems and is responsible for administering security classifications and access authorization in accordance with criteria established by data stewards, applying defined standards and business rules, applying controls and measures, and retaining information according to retention standards.

Legitimate Business Reason – A purpose that is necessary to perform a business function or operation and is not prohibited by applicable rules. Legitimate business, services or administrative needs include but are not limited to:

- employment administration
- investor relations activities
- business requests
- providing natural gas or electric services to customers
- acquisition, divestiture or reorganization activities
- financing activities
- others as required by law, judicial processes or administrative federal, state or local agency

Person – Any individual, partnership, corporation, trust, estate, cooperative, association, government, government subdivision or agency, or other entity.

Personal Information (PI) – Any individually identifiable information, that Duke Energy owns, licenses, maintains, possesses or over which it retains custody or control including, but not limited to:
(1) name;
(2) home or other physical address;
(3) email address or other online contact information such as an online user ID or screen name;
(4) telephone number;
(5) national identification number (e.g., a Social Security number);
(6) driver's license number or other government-issued identification number;
(7) digital or electronic signature;
(8) employer-assigned ID number;
(9) medical information (such as information regarding an individual's medical history, mental or physical condition, or medical treatment or diagnosis by a health care professional);
(10) health insurance information (such as an individual's health insurance policy number or subscriber identification number and any unique identifier used by a health insurer to identify the individual);
(11) account numbers and information (such as financial accounts and utility accounts);
(12) payment card data (including primary account number, expiration date, security code, PIN and data stored on the magnetic strip or chip of a payment card);
(13) access or security code, password, or security question and answer;
(14) biometric data;
(15) genetic data;
(16) persistent identifier that can be used to identify an individual (e.g., a device identifier such as a meter number or HAN number);
(17) data specifying an individual's geolocation; or
(18) any information that is combined with any of (1) – (17) above including, but not limited to, information regarding an individual customer's energy usage. Personal Information does not include aggregated or anonymized data that is not reasonably likely to allow the identification of an individual.

Personally Identifiable Information (PII) – Personal Information (PI) and Personal Identifiable Information (PII) can be used interchangeably but for purposes of this document it will be referred to as PII.

Data Privacy Coordinator – Individual responsible for overseeing compliance with the Data Privacy Program relative to his/her respective business function/unit.

Process – With respect to information, means to automatically or manually collect, record, organize, store, adapt or alter, retrieve, consult on, use, disclose, disseminate or otherwise make available, align or combine, block, erase or destroy.

Third Party – Individual or entity other than Duke Energy and its subsidiaries and affiliates.

Requirements

The functional/business units listed below are required to designate a Data Privacy Coordinator:

- Legal
- Corporate Compliance
- Human Resources
- Customer Operations
- Nuclear
- Generation
- Investor Relations
- Information Technology
- Other business functions/units as necessary

Duke Energy will:

- Implement reasonable and appropriate processes or mechanisms to assure PII is:
  - Accurate, complete and timely for the purposes for which it is being used, and accessible to fulfill a Legitimate Business Reason.
  - Protected from loss, misuse or alteration, to the extent required by law.
  - Encrypted when stored on laptops or other portable devices, transmitted wirelessly or transmitted across public networks, to the extent required by law and to the extent technically feasible.
  - Disposed of properly when the Legitimate Business Reason for maintaining the PII ends.
- Create, access, copy, delete, modify or maintain customer accounts or other similar Company records, only when there is a Legitimate Business Reason for doing so.
- To the extent required by law, provide notice to persons regarding the intended use of PII, and in the event of a breach of PII.
- Give persons the opportunity to exercise a choice regarding how PII collected by Duke Energy may be used, to the extent required by law.
- Include Social Security numbers in mailed correspondence only when required by law and only if the Social Security number is not visible during mailing.

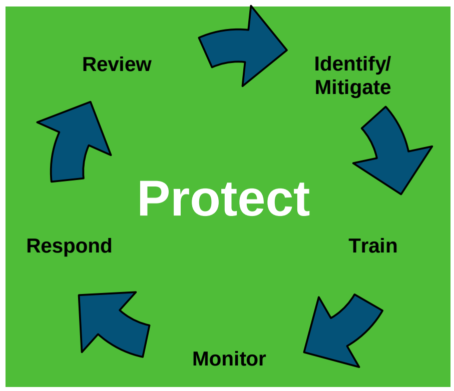
Duke Energy will NOT, unless permitted by law:

- Communicate PII to any third party unless there is a Legitimate Business Reason and the proper due diligence has been conducted to ensure compliance with this Standard.
- Print or embed a Social Security number on a card required to access products or services.
- Require an individual to transmit a Social Security number over the Internet unless either the Social Security number is encrypted or the Internet connection is secure.
- Require an individual to use a Social Security number to access an Internet site unless an authentication device such as a password is also used.
- Authorize employees or contingent workers to create, access, copy, delete, modify or maintain company records, employee records or customer accounts on behalf of themselves or to assist family, friends or acquaintances, etc. without prior written approval from the employee's or contingent worker's supervisor.

Duke Energy may, pursuant to a court order, subpoena, other legal process or government request, share PII. The Duke Energy Data Privacy Attorney should be consulted before any such requests are fulfilled.

Objectives

The objectives of this Standard are to mitigate the risks of unlawful disclosure or transmission of PII and prevent identity theft as described in the framework below:



I. Identify and Mitigate Risks

Applicable Data Privacy Coordinators shall develop and maintain a process to perform an annual Privacy Impact Assessment (PIA). The PIA will help the business discover and understand what PII it processes and how well it is protected. The PIA will be conducted by:

1. Documenting an inventory of PII the business function/unit processes and the systems, interfaces, procedures or practices, automated or manual, that are impacted. The inventory should include but is not limited to items such as:
   - Data description (e.g., SSN, checking account or credit card numbers, etc.)
   - Business requirement for processing the data
   - Information Owner/Data Steward
   - Responsible department
   - Impacted electronic systems or non-electronic processes
   - Third parties or other business functions that have access
   - Existing mitigating factors
2. Identifying the risks associated with the inventory of PII including ensuring a Legitimate Business Reason exists for processing the PI
3. Determining if adequate mitigating controls are implemented
4. Enhancing mitigation where necessary

II. Train

Training is required for all workforce who collect, use, store or have access to PII in order to communicate how to comply with the requirements of the Data Privacy Program.

Each Data Privacy Coordinator shall coordinate with Corporate Compliance to define his/her respective target audience for the training.

Corporate Compliance will administer data privacy and identity theft training, at least annually, to individuals who have physical or electronic access to PII in the following business functions:

- Legal
- Ethics and Compliance
- Customer Operations

- Human Resources
- Investor Relations
- Nuclear
- Generation
- Information Technology
- Other functional areas as needed

III. Monitor

Corporate Compliance and/or the Data Privacy Attorney shall monitor:

- New or updated legislation that impacts Duke Energy, its policies, standards or procedures
- Compliance with this Standard by confirming and documenting the following:
  - PIAs are conducted annually
  - Training is completed annually
  - List of Data Privacy Coordinators is updated
  - Chief legal officer and board of directors, or appropriate committee thereof, are informed of significant matters

IV. Respond

Exposures may have a significant impact to Duke Energy and may harm the individuals whose PII has been released or breached. All Exposures that may impact Duke Energy or others shall be identified and handled in accordance with this Standard.

When an Exposure occurs and is discovered, the Data Privacy Attorney must be consulted prior to any discussions internally, with the media or with potentially impacted individuals.

All reported potential Exposures must be investigated in accordance with the Exposure Response Plan (refer to Exhibit A for a decision matrix of the Plan) as described below:

Identify and Report

Identified Exposures shall be reported immediately as follows:

<u>Lost/Stolen Assets</u>

When Duke Energy assets (laptops, desktops, BlackBerrys, handheld devices, etc.) have been lost or stolen, the loss or theft shall be reported to the Enterprise Help Desk at 704.382.4357 as soon as possible.

<u>Other Exposures</u>

Any Duke Energy employee, contingent worker or third party performing work or services for, or on behalf of, Duke Energy who suspects or witnesses an Exposure of PII shall immediately contact his/her manager, supervisor or Duke Energy contact. The notified person shall then contact one of the following to report the event:

- Respective Data Privacy Coordinator
- Corporate Compliance (CorporateCompliance@Duke-Energy.com)
- Data Privacy Attorney
- EthicsLine (allows for anonymous tips): 866.838.4427

If the initial report does not come in through Corporate Compliance, then the above mentioned contact who received the notification should inform Corporate Compliance immediately. All reported Exposures should be treated as confidential until determined otherwise.

Assess

Corporate Compliance, with legal counsel, will determine if the reported event warrants an investigation by collecting and assessing initial facts. Corporate Compliance will use consistent processes (i.e. Incident Investigation Forms) to gather the relevant information. If an investigation is not warranted, Corporate Compliance will document and communicate, when feasible, to the reporting party and no further actions will be taken. If an investigation is warranted, the Data Privacy Attorney will determine if the investigation will be conducted under attorney-client privilege.

For employee behavioral-related matters, Corporate Compliance will consult with and/or transfer the case to the Ethics Office. For example, if an employee is allegedly harvesting company information on a non-approved storage device or sending company information to a non-Duke Energy email address.

For any matters involving an executive, VP level or above, Corporate Compliance will inform the Chief Ethics and Compliance Officer.

For potential issues discovered by IT's Data Loss Prevention (DLP) tools, these will be sent to Enterprise Protective Services (EPS) for evaluation and if needed investigation.

For any matters involving Duke Energy systems, we'll need to make Deloitte (our external audit) aware of the matter.

Finally, as necessary, mitigation efforts or corrective actions will be immediately initiated to address any gaps that led to the exposure.

Escalation Procedures

Effective January 3, 2018, Ethics and Compliance posted a revised version of the Duke Energy Escalation Procedures. The Data Privacy team is responsible for leveraging these Duke Energy Escalation Procedures when compliance issues arise. Compliance concerns that could require Mandatory Notification and Escalation to Ethics and Compliance include but are not limited to issues or concerns such as:

1. Mandatory Notification triggers noted in the procedure. (e.g. Moderate or large financial consequences; prolonged or long-term (>6 months) loss of confidence by multiple stakeholder groups; agency action(s); many customers are affected; Senior Management involved).
2. Immediate Response: (e.g. Events or conditions of actual or potential noncompliance that require immediate action to prevent Severe or Critical legal, regulatory, or reputational impact(s).
3. Violations of the Law, Regulation or CoBE: (e.g. Events or conditions indicating a violation or potential violation of a Federal, state, or local law or regulation, or the CoBE).
4. Government Agency: A Severe or Critical self-report, report of potential noncompliance to a government agency that may trigger a significant negative regulatory agency action, or significant straining of productive relationships with a regulatory agency.
5. Changes in Risk Profiles: New or emerging laws and regulations, changes in business activities, or other shifts in the compliance environment that can, or will, significantly impact the risk profile of the compliance area or business unit.
6. Adequacy of Controls.

Investigate

Corporate Compliance will lead a timely investigation, working with the Data Privacy Coordinator, to determine if an Exposure occurred. Guidance from Legal will be obtained throughout the investigation.

As needed for each incident, develop an incident communication plans including:

1. Identification of an incident leader and a person with signoff authority, with defined ownership; the such a leader and signoff authority person should be an organization level commensurate to the magnitude of the incident
2. Clearly define investigation roles and responsibilities for a data breach incident
3. Establishment of deadlines
4. Review escalation process to ensure all appropriate parties are notified on a timely basis
5. Notification timing to drive consistency between all involved parties
6. Ensure protocols include consideration of litigation and signoff authority for messages/communications
7. Delivery approach (email, US mail, carrier, etc.)
8. Resources for mail merges/email merges
9. Protocols to establish who to call with questions

Under the Corporate Compliance SharePoint, we have a site called **"Data Privacy Incident Collaboration"**. In this site we'll create separate folders for each incident that requires cross department collaboration. Note: all the official, and confidential, incident case files will be located in the case folders within the **"Data Privacy"** folder to which only E&C and Legal will have access. The **Data Privacy Incident Collaboration"** has a template folder where templates from prior cases can be stored and used for future cases. This template folder may include templates and additional subfolders such as:

1) Communications Plan
   a) Notice letter to affected persons
   b) Notice letter to state AG
   c) Letter to employees
   d) Heads up notice to regulatory attorneys
   e) Executive updates
   f) Call Center FAQs
   g) Media responses
   h) Portal and/or web postings
2) Legal Matters
   a) Attorney Client Privilege advice
   b) Legal Hold notice
   c) Electronic Evidence Request Forms
   d) Evidence Control Form
   e) Documentation of retention of outside counsel
   f) Documentation of retention of outside experts
3) Administrative
   a) Factual description of matter
   b) Timeline
   c) Schedule of status calls
   d) Team investigative assignments
   e) Team roster and contact info
   f) (Incident leader and communications approver identified)
4) Investigation
   a) Investigation reports and related evidence

The Data Privacy Coordinator or designee for the respective business function will:

1. Facilitate completion of the Incident Investigation Form provided by Corporate Compliance and assist with the discovery and documentation of related facts.
2. Coordinate investigation activities and findings with Corporate Compliance, who will facilitate discussions with legal counsel.

Corporate Compliance will use consistent processes (e.g. Incident Investigation Forms) to gather the relevant information. As appropriate, Corporate Compliance and Legal will engage the following subject matter experts and/or stakeholders throughout the investigation:

a. Cyber Security or data expert
b. Business contact – data owner
c. Business contact – area where data release occurred
d. Business Data Privacy Coordinator
e. Labor Relations
f. Labor Relations attorney
g. Employment attorney (includes HIPAA matters)
h. Jurisdictional attorney
i. Senior management
j. Call Center (e.g. credit monitoring)
k. Corporate Communications
l. Third party subject matter experts when determined necessary by Legal

If an Exposure is confirmed, all exposed data must be identified and documented including the potentially impacted individuals' names, mailing addresses, what data was exposed, etc.

If an Exposure is not confirmed, skip to the Document section.

Mitigate and Cause Analysis

The responsible information owner or designee, Data Privacy Coordinator and Corporate Compliance will review the events related to the Exposure to determine if additional or enhanced mitigating controls are necessary to prevent similar incidents from occurring in the future. Corporate Compliance will assist the responsible functional/business unit with the design and implementation of any mitigating controls or procedures determined to be necessary. Mitigation shall be implemented in a timely manner.

More information on Cause Analysis can be found in the NERC Corporate Compliance - **Cause** Analysis Procedure. This process provides a systematic approach that identifies the fundamental reason or cause that a problem has occurred. This process provides guidance on various tools and methodologies available to determine direct cause, apparent cause or the root cause, based on the significance of the problem. This process in conjunction with other tools that are available on the NCC SharePoint. Effective determination of causes and the implementation of appropriate corrective actions results in the use of these tools and methodologies. The cause analysis process is essential to find the cause(s) and create corrective actions to prevent reoccurrence.

Notify

Duke Energy may have a legal obligation to notify individuals and/or governing bodies that certain Exposures or Breaches have occurred. Notifications are time sensitive and shall be performed with advice from Legal.

Required notifications shall be provided, in accordance with applicable law, by the functional/business unit responsible for the data.

Corporate Compliance, Legal, the business, and regulatory attorneys from impacted jurisdictions will develop a notification plan which will include drafting notification letters and other communications to internal and external stakeholders. Corporate Compliance will provide credit monitoring tokens when warranted.

Expenses associated with the notification and risk mitigation process are the responsibility of the Data Sponsor's designated department or other parties as agreed to with the Data Sponsor.

Document

The Data Privacy Attorney, with assistance from Corporate Compliance, will consolidate and retain documentation regarding each Exposure or Breach in accordance with the applicable statute of limitations and the Duke Energy Records Management policy.

Communicate

The Data Privacy Attorney will advise Corporate Compliance and the Data Privacy Coordinator when to communicate any potential Exposure or Breach to management and other stakeholders as the investigation is conducted.

V. Review

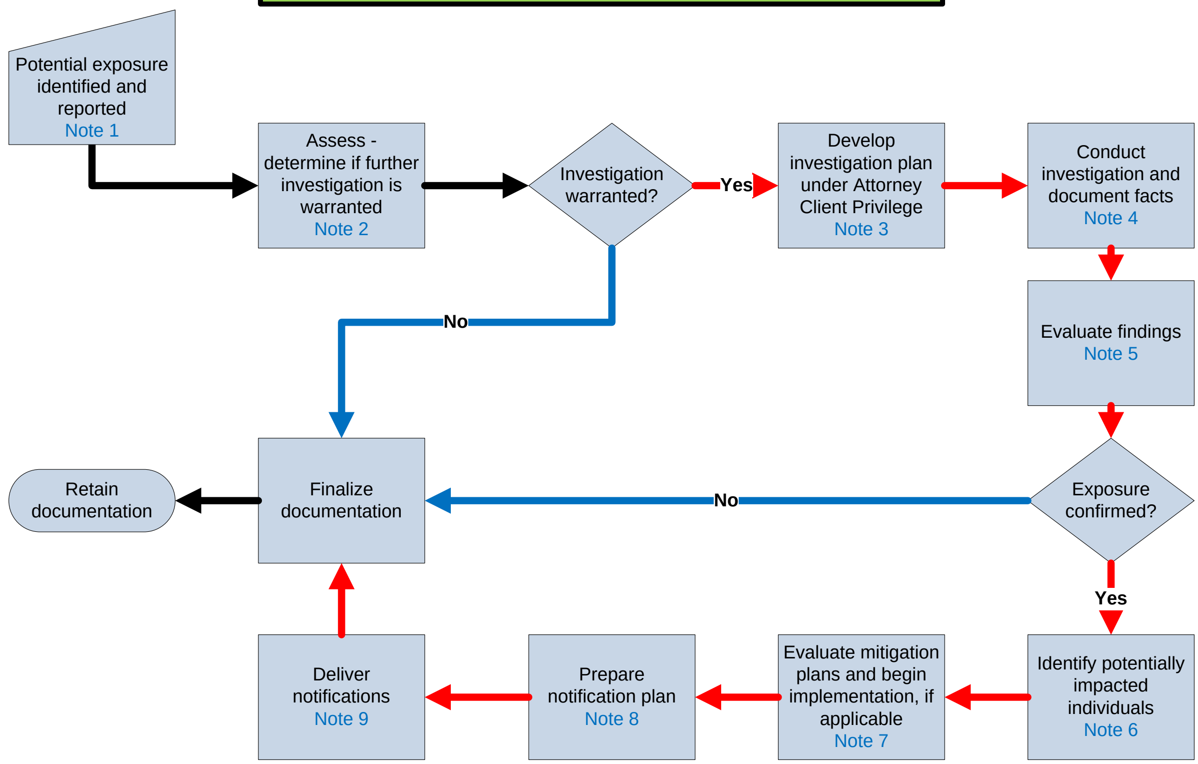
This Standard shall be reviewed by the Data Privacy Attorney, Corporate Compliance and the Data Privacy Coordinators periodically to evaluate its continued effectiveness in assisting Duke Energy to:

- Maintain compliance with new or changing applicable laws, regulations and policies
- Mitigate new risks or methods of committing identity theft or identity fraud
- Enhance processes or controls as necessary

Exhibit A

62M

Exposure Response Plan



Notes:

1 Potential data privacy Exposures should initially be reported to one of the following contacts: Corporate Compliance, Data Privacy Attorney, respective Data Privacy Coordinator or the EthicsLine; or to the Enterprise Help Desk for lost or stolen assets. If the initial report does not come in through Corporate Compliance, then the contact who received the notification should inform Corporate Compliance immediately. Corporate Compliance will use consistent processes (e.g. Incident Investigation Forms) to gather the relevant information. All reported Exposures should be treated as confidential until determined otherwise.

2 Corporate Compliance will consult with Legal and the business as necessary. For employee behavioral-related matters, Corporate Compliance will consult with and/or transfer the case to the Ethics Office. For any matters involving an executive, VP level or above, Corporate Compliance will inform the Chief Ethics and Compliance Officer. Additionally, the Duke Energy Escalation Procedures and associated notifications will be followed for each incident.

3 Corporate Compliance and Legal will partner to develop the investigation plan. Various internal (e.g. Cyber Security, business data owner, regulatory and business attorneys, Labor Relations, etc.) and/or external parties may be consulted as needed depending on significance, subject matter and business unit. Additionally, Legal may contract with external parties as needed. When warranted, the investigation plan will be modified.

4 Corporate Compliance will lead the investigation. Privacy Coordinators and/or subject matter expert investigators will document all facts and supporting information.

5 Corporate Compliance will work with the applicable parties to identify various factors such as data type, location of exposure or potentially impacted individuals, etc. Corporate Compliance, with guidance from Legal, will evaluate all applicable laws, rules, regulations and obligations.

6 All exposed data must be identified and documented down to the potentially impacted individuals' names, mailing addresses, what data was exposed, etc. Corporate Communications and other stakeholders will be engaged if necessary.

7 The business complete cause analysis (i.e. root cause) and will establish a mitigation plan. Compliance and Legal will review the plan to confirm that it will alleviate the issue and mitigate the risk of future reoccurrences.

8 Corporate Compliance, Legal, the business, and regulatory attorneys from impacted jurisdictions will develop a notification plan which will include drafting notification letters and other communications to internal and external stakeholders. Corporate Compliance will provide credit monitoring tokens when warranted.

9 Notifications may need to be delivered to the potentially impacted individuals, various governing bodies and affected third parties.

Appendix B – Smart Meter Incident Report

Pursuant to the Commission's June 22, 2018 Order Approving Manually Read Meter Rider with Modifications and Requesting Meter-Related Information entered in Docket Nos. E-7 Sub 1115, E-100 Sub 147, and E-7 Sub 153, Duke Energy Carolinas, LLC ("DEC" or the "Company") submits the following information regarding the concerns submitted by commenters alleging smart meters have caused fires, power outages, interference with devices such as pacemakers, and inaccurate bills:

The Company has investigated the claims and concerns of the commenters in this docket and has determined there have been no incidents of fire, power outages, interference with devices such as pacemakers, and inaccurate bills related to the Company's model of smart meters. The company would like to note that several customer complaints have been received where customer perception is that the new smart meter has caused an increase in customer's bill. The company has thoroughly investigated each of these complaints and have never found a smart meter providing inaccurate usage data.

Appendix C - Cyber Security Risk Report

2018 Smart Grid Technology Plan of Duke Energy Carolinas, LLC
Appendix C to Section 7
Smart Meter Cyber Security Risk Report

Pursuant to the Commission's June 22, 2018 Order Approving Manually Read Meter Rider with Modifications and Requesting Meter-Related Information entered in Docket Nos. E-7 Sub 1115, E-100 Sub 147, and E-7 Sub 153, Duke Energy Carolinas, LLC ("DEC" or the "Company") submits the following information regarding cyber incidents, at DEC or elsewhere, involving the Company's model of smart meters, and how the occurrences were resolved:

The Company has investigated the claims and concerns of cyber security incidents and has determined there have been no related to the Company's model of smart meters. Additionally, the Company reached out to Itron and received confirmation from Peter Flack, Director Information Security, stating there are no confirmed cyber incidents at DEC or elsewhere, involving Itron OpenWay meters. A copy of the letter from Mr. Flack is attached.

Itron

September 5, 2018

Don Schneider
GM MajorProjects-GridSolutions
400 South Tryon ST-0313
Charlotte, NC 28202

Dear Don,

We received a question regarding known cyber incidents that Itron has experienced with Itron OpenWay® meters. Please allow this letter to convey that there are no confirmed cyber incidents at DEC or elsewhere, involving Itron OpenWay meters.

Sincerely,

Peter Flack
Director Information Security
Itron, Incorporated

Cc: Robert Moreland – Duke Energy, Carolina AMI Project Director
Mike Pasquino – Itron, Account Executive
Leslie Thrasher – Itron, Sr. Business Operations Manager

ITRON
2111 North Molter Road
Liberty Lake, WA 99019
www.itron.com

Appendix D – Opt-Out Report

Pursuant to the Commission's June 22, 2018 Order Approving Manually Read Meter Rider with Modifications and Requesting Meter-Related Information entered in Docket Nos. E-7 Sub 1115, E-100 Sub 147, and E-7 Sub 153, Duke Energy Carolinas, LLC ("DEC" or the "Company") submits the following information regarding the number of customers on the Company's Manually Read Meter Rider (Rider MRM), with separate data for those who opt out for health reasons and for those who opt out for any other reason:

The Company's Rider MRM is effective October 1, 2018 and, therefore, the company does not yet have any customers enrolled in the rider. The Company will update this information it's the next Smart Grid Technology Plan.

IVVC Cost* Details

***Class 5 Estimate (-20% to +50%)**

Nominal

Capital									
COSTS ($1,000)	NPV	Year 1	Year 2	Year 3	Year 4	Year 5	Total Deployment	Years 6-26	Total 26 Year
TRANSMISSION	130,081	0	23,537	24,098	24,673	25,262	97,569	155,633	253,202
TELECOM	45,185	0	8,140	8,335	8,533	8,737	33,746	75,384	109,129
IT	10,318	0	2,566	2,451	2,510	2,385	9,913	6,194	16,107
DISTRIBUTION	206,738	812	47,937	49,080	50,251	51,264	199,344	124,953	324,297
PM / AFUDC	23,750	332	6,288	7,026	7,188	7,280	28,113	0	28,113
Total Capital	416,072	$1,144	$88,469	$90,989	$93,155	$94,928	$368,685	$362,164	$730,849
O&M									
TRANSMISSION	9,578	0	212	217	223	228	881	23,921	24,802
TELECOM	11,023	0	76	78	80	81	314	27,751	28,065
IT	12,614	0	0	0	0	0	0	776	776
DISTRIBUTION	29,967	392	2,298	2,355	2,414	2,388	9,846	6,796	16,642
PM / AFUDC	0	0	0	0	0	0	0	0	0
Total O&M	63,183	$392	$2,585	$2,650	$2,716	$2,698	$11,041	$59,243	$70,285
TOTAL IVVC Costs	479,255	$1,536	$91,054	$93,639	$95,871	$97,626	$379,726	$421,407	$801,134

Cost with Revenue Requirement

Capital									
COSTS ($1,000)	PVRR	Year 1	Year 2	Year 3	Year 4	Year 5	Total Deployment	Years 6-26	Total 26 Year
TRANSMISSION	178,519	0	30,882	31,619	32,373	33,146	128,020	203,651	331,670
TELECOM	62,028	0	10,681	10,936	11,197	11,464	44,277	98,642	142,919
IT	13,885	0	3,367	3,216	3,293	3,129	13,006	8,105	21,112
DISTRIBUTION	278,225	1,074	62,897	64,398	65,935	67,262	261,565	163,505	425,071
PM / AFUDC	31,322	439	8,251	9,219	9,431	9,551	36,891	0	36,891
Total Capital	563,979	$1,513	$116,077	$119,389	$122,229	$124,552	$483,759	$473,904	$957,663
O&M									
TRANSMISSION	9,582	0	212	217	223	228	881	23,921	24,802
TELECOM	11,024	0	76	78	80	81	314	27,751	28,065
IT	12,614	0	0	0	0	0	0	776	776
DISTRIBUTION	30,007	392	2,298	2,355	2,414	2,388	9,846	6,796	16,642
PM / AFUDC	0	0	0	0	0	0	0	0	0
Total O&M	63,228	$392	$2,585	$2,650	$2,716	$2,698	$11,041	$59,243	$70,285
TOTAL IVVC Costs	627,207	$1,904	$118,663	$122,039	$124,945	$127,249	$494,800	$533,147	$1,027,947

IVVC Benefit Details (with CO2 Benefit)

A negative ( ) value in the Benefits tables represents avoided costs or savings.

BENEFITS ($1,000) : With C02 Benefit

BENEFITS ($1,000)	NPV	Year 1	Year 2	Year 3	Year 4	Year 5	Total Deployment	Years 6-26	Total 26 Year
Operational Benefits									
Improved VAR Mgt	(89,233)	0	(1,585)	(3,065)	(4,660)	(6,321)	(15,631)	(199,688)	(215,319)
Capacity Deferral	(112,201)	0	(2,352)	(4,763)	(7,236)	(9,770)	(24,120)	(236,411)	(260,532)
Fixed O&M	(4,572)	0	0	0	0	0	0	(15,805)	(15,805)
Variable O&M	(23,884)	0	0	0	(434)	(701)	(1,135)	(63,563)	(64,698)
Reagent Cost	(282)	0	0	0	1	(7)	(6)	(775)	(781)
Start Cost	(11,963)	0	0	0	87	(433)	(345)	(41,335)	(41,681)
SUBTOTAL:	(242,136)								
Customer Benefits									
Fuel	(369,220)	0	0	0	(6,114)	(11,097)	(17,211)	(1,044,932)	(1,062,142)
SUBTOTAL:	(369,220)								
Operational Benefits and Customer Benefits									
SUBTOTAL:	(611,356)								
Environmental Benefits									
SO2	(7)	0	0	0	(0)	(1)	(1)	(15)	(15)
Nox	(341)	0	0	0	(8)	(19)	(27)	(795)	(823)
CO2	(115,007)	0	0	0	0	0	0	(371,301)	(371,301)
SUBTOTAL:	(115,355)								
TOTAL (all benefits):	(726,711)	0	(3,937)	(7,828)	(18,363)	(28,348)	(58,477)	(1,974,621)	(2,033,097)

TOTAL COST

COSTS ($1,000)	NPV	Year 1	Year 2	Year 3	Year 4	Year 5	Total Deployment	Years 6-26	Total 26 Year
Total Capital	563,979	1,513	116,077	119,389	122,229	124,552	483,759	473,904	957,663
Total O&M	63,228	392	2,585	2,650	2,716	2,698	11,041	59,243	70,285
TOTAL Capital & O&M	627,207	$1,904	$118,663	$122,039	$124,945	$127,249	$494,800	$533,147	$1,027,947

Key Financials:

Key Financials	
Investment Period:	26 Years
Net Present Value (NPV):	$99,504 M
Benefit / Cost Ratio (26 Year NPV):	1.16

IVVC Benefit Details (without CO2 Benefit)

A negative ( ) value in the Benefits tables represents avoided costs or savings.

BENEFITS ($1,000) : (Without CO2 Benefit)									
BENEFITS ($1,000)	**NPV**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total Deployment**	**Years 6-26**	**Total 26 Year**
Operational Benefits									
Improved VAR Mgt	(89,233)	0	(1,585)	(3,065)	(4,660)	(6,321)	(15,631)	(199,688)	(215,319)
Capacity Deferral	(112,201)	0	(2,352)	(4,763)	(7,236)	(9,770)	(24,120)	(236,411)	(260,532)
Fixed O&M	(6,008)	0	0	0	0	0	0	(18,750)	(18,750)
Variable O&M	(21,951)	0	0	0	(103)	(859)	(962)	(58,095)	(59,057)
Reagent Cost	(200)	0	0	0	(5)	(4)	(8)	(602)	(610)
Start Cost	(19,727)	0	0	0	(578)	(593)	(1,171)	(59,856)	(61,027)
SUBTOTAL:	(249,320)								
Customer Benefits									
Fuel	(386,062)	0	0	0	(6,255)	(11,401)	(17,656)	(1,077,672)	(1,095,328)
SUBTOTAL:	(386,062)								
Operational Benefits and Customer Benefits									
SUBTOTAL:	(635,382)								
Environmental Benefits									
SO2	(11)	0	0	0	(0)	(0)	(1)	(24)	(24)
Nox	(385)	0	0	0	(5)	(12)	(16)	(957)	(973)
CO2	0	0	0	0	0	0	0	0	0
SUBTOTAL:	(396)								
TOTAL (all benefits):	(635,778)	0	(3,937)	(7,828)	(18,841)	(28,959)	(59,565)	(1,652,055)	(1,711,620)

TOTAL COST									
COSTS ($1,000)	**NPV**	**Year 1**	**Year 2**	**Year 3**	**Year 4**	**Year 5**	**Total Deployment**	**Years 6-26**	**Total 26 Year**
Total Capital	563,979	1,513	116,077	119,389	122,229	124,552	483,759	473,904	957,663
Total O&M	63,228	392	2,585	2,650	2,716	2,698	11,041	59,243	70,285
TOTAL Capital & O&M	627,207	$1,904	$118,663	$122,039	$124,945	$127,249	$494,800	$533,147	$1,027,947

Key Financials:

Key Financials	
Investment Period:	26 Years
Net Present Value (NPV):	$8,571 M
Benefit / Cost Ratio (26 Year NPV):	1.01

SGTP Exhibit 2 – Commission's Rules on Third Party Access to Customer Usage Data

The North Carolina Utilities Commission's March 7, 2018 *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data* (March 7, 2018 SGTP Order) in Docket No. E-100, Sub 147, directed Duke Energy to convene meetings with the NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data; file a report with the Commission providing the details of the discussions and the parties' plans for further discussions; and reflect the results of these stakeholder discussions in its 2018 SGTP reports.

Pursuant to the March 7, 2018 SGTP Order, Duke Energy held a discussion with the parties in Raleigh, NC on May 23, 2018. In attendance were representatives from Duke Energy, Dominion Energy, Public Staff, NCSEA, Plot Watt, City of Durham/Durham County, SELC, and EDF. A report of the May 23 meeting was filed on June 21, 2018 in Docket No. E-100, Sub 147. Based on the discussion at the May 23 meeting, Duke Energy and the parties decided to have a series of breakout meetings to allow for the in-depth discussion of specific topics with the involvement of needed experts. Those breakout topics were for Data Definition (granularity, data fields, validation, etc.), Cost (implementation estimates and cost recovery approach), Compliance and Authorization (3rd party registration and certification process), and Customer Experience. Breakout discussions were completed and the parties reconvened as a whole on July 10, 2018. The following is a summary of the conference:

Customer Usage Data Access Conference *Summary & Next Steps – July 10, 2018*

A second conference between Duke Energy and interested third parties was held in Raleigh, NC on July 10, 2018 at 9am EDT to further review and discuss certain elements of Green Button's data sharing policy, such as data definition, cost, compliance and authorization, customer experience.

Attendees: Duke Energy, Dominion, NC Public Staff, NCSEA, Plot Watt, City of Durham/Durham County, SELC, Environmental Defense Fund, Mission Data, Energy NC

Discussion Topics:

- **Data definition**
    - There are four categories (customer data, billing data, usage data, and systems data) of information that capture the range of customer information that can be / should be portable to customers.
        - Any information that is specific to the customer, or generated by the activity of the customer – such as energy usage and resulting bills is referred to as "standard customer data."
    - Customer data (name, address, phone number, other basic info, etc.)
        - Ties to account (helps with multi-premise)
        - Customer needs to provide consent initially
        - Hardware constriction from AMI meter, may be bound by this
    - Usage file (provided more frequently)

            - Amount of historical – four years is seen as best practice
            - System data points for demand response & wholesale market customers
            - Two pieces of data
                - PII (personal identifiable information) Customer Data
                - Non PII Usage data
            - Ties to meter
            - Kwh based on interval
            - We already have access to this, just a matter of putting it into Green Button framework
            - Today, customers can go to portal and download usage data and always download in hour interval, meter interval differs by metering instructions
            - Ideal to have 15 min interval esp. for commercial customers
        - There's a unique identifier which can link these files
        - Taking the "Best Available" data can be an important approach
        - Quality of reading indicator:
            - Raw
            - Validated
        - 24 hour turnaround is acceptable and complies with standard
        - Possible indicator that it failed validations, versus providing a zero read
        - Size of file can be handled by utility – and compressed if needed
        - Meter changes:
            - What is the level of authentication?
                - Meter or
                - Customer or
                - Premise or
                - Account
        - Utilities and Green Button now looking at also providing PDF version of Bill to 3rd party (versus customer providing login/password to website)
        - There was a request to provide a database (comma delimited, etc.) file of billing information – machine readable format

- **Cost – to identify cost / benefit elements. Discussion included:**
    - System Development Costs – John Finnigan named two vendors that were used by other companies, including Schneider Electric and O'Power. Duke could ask for bids to offer this as a monthly software lease or Duke could build our own.
    - Ongoing transmittal of the Data to the 3rd parties
    - Creation and maintenance of a testing environment for 3rd parties
    - Vendor Authorization and Registration Process
    - Stakeholder/Customer Engagement
    - Customer Signup
    - IT Security / Cyber Audits
    - AMI Obsolescence Risk – Doubtful this would be monetized in a CBA but there could be a future where the 3rd party vendors determine that a different kind of data not currently captured by AMI would prove beneficial. This would likely have impacts on customer rates.

- Data Breach Risk – This is primarily dealt with in the contractual agreements between Duke and the Customer and Duke and the 3rd Party. In both cases, Liability Waivers would be absolutely necessary.

- **Authorization**
  - This element encompasses providing standardized language for the customer to support their informed consent.
  - Third parties required to provide utilities certain criteria (see below)
    - Contact info, including federal tax ID number
    - Certificate of good standing from the state
    - Agree to reasonable terms of utility data access
    - Complete technical interoperability test with a utility's GBD platform
  - In other states – the utility checks that criteria are met, but no arbitrator role
    - Often the commission investigates reports of bad actors
    - Commission could declare them a bad actor and they would be black listed from receiving usage information
  - Performance standard (bandwidth and security)
  - Some states put it on the customer to decide and require the customer to realize the risk
  - Data breaches should be disclosed – California required disclosure of any breaches of a third party or any transfer-related issues
  - Registration (customer) is different than Authorization/Certification (3rd party)
  - For utility list of third party, the utility will be provided a logo and link to the services the third party provides
  - Purpose of consent – if the third parties purpose changes, it should require additional/regained consent
  - Requirement for ability of customer to grant access and registration to send data to third party
    - Look at continuation of how to reauthorize (How often to require? What is the customer experience – needs to be defined)
  - Need to understand role of commission regarding revocation – may likely require additional rulemaking

- **Customer experience**
  - Review of five discrete authorization processes for customers. These processes should make use of a customer's online utility account, if one is already created, but a utility account should not be required. These include:
    - 1. Customer has an online utility account
    - 2. Authorization without a utility account
    - 3. Customer authorization via Third Party designs
    - 4. Warrant process
    - 5. A paper-based form
  - Consider customers with many facilities – review use cases here (e.g., property owner vs lessor, energy manager for school district, apartment complex, etc.)
  - Test environment is critical (we would need to test the different authorization processes to ensure they function properly prior to go-live)

Next Steps:

- **Data definition**
    - Review current files / embedded fields (e.g., tariff profile, usage summary, interval blocks) to understand if format will work / be meaningful for customers
    - Review schema, choose fields of interest; leverage best practice / expectations from this group

- **Cost – determine if cost can be recovered through base rates**
    - Review business case and customer adoption rates for Excel Energy model in Colorado, Ontario Commission
    - Review New York Utility Commission re: utilities' justification for selecting Green Button
    - Conduct cost / benefit analysis for Duke Energy

- **Authorization –** Who is responsible for managing certificates of good standing?
    - (Document retention will likely be a hurdle (e.g., which function at utility does this, manual / paper process)

Duke Energy Progress

2018 Smart Grid Technology Plan

Table of Contents

Overview

As required by the North Carolina Utilities Commission (NCUC) Rule R8-60.1(b), Duke Energy Progress (DEP or Company) submits its 2018 Smart Grid Technology Plan (SGTP or Plan). The 2018 Plan represents the smart grid technologies being evaluated, designed, or implemented, and is the best projection of how the Company is making smart grid investments in the near term and leveraging emerging technologies for the future.

Duke Energy has many smart grid technology projects currently underway, and many more technologies and initiatives that are being evaluated for the future.

1. Smart Grid Technology Strategy

Reference	**Requirement**
R8-60.1 (c) 1	*A summary of the utility's strategy for evaluating and developing smart grid technologies.*

Building a smarter grid for North Carolina

Technology is transforming North Carolina, and changing the way customers use electricity and interact with their electric provider. Reliability remains essential as an increasingly connected population continues to expand, especially in urban areas of the state. Today, the need for consistent, reliable service isn't just the expectation of industry and manufacturing, but extends into every home and business – even at a time when that reliability is challenged by the increasing frequency of severe weather events and the very real threat of physical and cyber attack.

The century-old model of one-way power flow from power plant to customer is evolving to one of distributed resources, and customers are increasingly connecting to innovative technologies like private solar, battery storage, electric vehicles and microgrids. Power lines that were once the last mile of a constant and consistently flowing electric grid are now the first stop for a network of thousands of generation sources, pushing a dynamic flow of energy onto an energy highway that was never engineered for multi-directional flow.

Customers today want a new experience – a better experience - built upon information about how they personally use energy and tools to harness that energy and power their lives. And they want a power grid that can adapt to meet their changing energy needs, repair itself faster when there are problems and serve as the backbone of their lives and of the state's digital economy.

The reality is that today's grid, while well maintained, is simply not engineered to handle the changing demands it is being asked to serve. To deliver on customer expectations, we must do more than maintain the power grid; we must transform it, leveraging technology to modernize its operation, making it more reliable, smart and secure.

This means converting the grid from a radial one-way design to a two-way distribution system that can automatically route power from where it is produced, regardless of where that happens on the system, to where it is needed. Duke Energy has made excellent use of the existing grid system, but it and other utilities throughout the nation, must address issues such as DER challenges, physical and cyber security, increased convective weather events and increased customer reliance and expectations since the grid was initially built.

Grid Improvements

The Power/Forward Carolinas grid improvement initiative was developed to transform the state's electric grid, making it more reliable, while also making it smarter and more secure. The initiative is built around these core benefit areas:

- Improve reliability to avoid outages and speed restoration
- Harden the grid against physical and cyber impacts
- Expand solar and distributed technologies across a two-way, smart-thinking grid
- Give customers more options and control over energy use and tools to save money

Improve reliability

Initiatives in this category focus on all points of the grid, with some engineered to reduce the number of outages experienced on the system and others speeding restoration and improving resiliency when an outage occurs. Projects in this category include work to underground the most outage-prone lines on the distribution system, equipment upgrades on both the distribution and transmission system and an advanced smart meter network to improve outage detection and restoration response.

Foundational to improving reliability is a smart-thinking grid that can quickly identify and isolate outages when they occur, and automatically reroute power to speed restoration to customers. This self-optimizing system relies on an advanced network of monitoring and switching technology, as well as upgrades to power lines and other equipment. In some areas where redundant circuits are not available, battery storage and microgrid technology will be employed to restore service to customers while repairs are made.

Smart-thinking grid technology can reduce the number of customers affected by an extended outage by as much as 75 percent. If outages do occur on a smart-thinking grid, power is typically rerouted in less than a minute.

Harden the grid

The threat of severe weather, and physical and cyber attack are real and are among the greatest challenges that utilities face in an increasingly connected, digital world. Requirements to protect the grid and the risk of intrusion are orders of magnitude greater than what they were in the past. As one of the largest utilities in the nation, Duke Energy is a top target of cyberattacks.

Hardening improvements include equipment upgrades on the distribution and transmission system, flood mitigation, animal mitigation, system health tools, physical barriers and access control, and advanced communication and monitoring technologies.

When disruptions do occur, Duke Energy's grid and support systems must be engineered to recover quickly. Resilient energy systems must be designed to survive physical and cyber incidents while sustaining critical functions. Resiliency upgrades include system intelligence and self-healing capabilities through the company's smart-thinking grid deployment, as well as an expanded suite of defensive measures to keep pace with the new world of physical and cyber threats the company faces.

Expand solar and distributed technologies
In addition to improving reliability and resiliency after an outage, the smart-thinking grid will also support the two-way power flows needed to support more innovative technologies like rooftop solar, battery storage, electric vehicles and microgrids. The company is also expanding the use of renewables as part of the work to improve reliability, by using large-scale battery storage systems often powered by solar energy at points across the grid.

Give customers more options and control
When it comes to saving energy and money, information is power. And Duke Energy wants to provide customers with the intelligent information needed to make smart energy choices to conserve and lower their monthly bills. Smart meters are the foundation that helps provide customers detailed data about their energy use – including hourly, daily and average usage – showing them how much energy they are using and when. Having this information available on a daily basis can help customers make informed energy decisions to save money before their bill arrives.

Smart meters are also the gateway to more customer options and control, enabling options like usage alerts, improved outage detection and new programs tailored to help customers make smarter energy choices and take advantage of new technologies.

Driven by data
Duke Energy's grid improvement initiative is built on millions of data points that help target improvements to maximize customer benefits. By targeting investments, we can also keep costs lower for customers while preparing the grid for new technologies that will benefit communities, the environment and our state.

Data is also the foundation of the smart-thinking grid – a system that is more secure against physical and cyber attacks and that anticipates outages and intelligently reroutes power when an outage occurs – keeping service reliable and the power on when customers need it most. Data is also driving the optimization of the grid that will enable Duke Energy to deliver power more efficiently, and support the two-way flow of electricity necessary to grow renewable and emerging technologies like rooftop solar, battery storage, electric vehicles and microgrids.

Smart grid technologies

Certain programs included in the Power/Forward Carolinas grid improvement initiative are technologies that fall under the definition of "smart grid technologies" outlined in Commission Rule R8- 60.1(c), while others are not. All of the programs have similar objectives in the long term, improving reliability and resiliency of the grid; however, certain programs, like Targeted Undergrounding, are not deemed smart grid technologies rule by definition. The Company has determined that smart-thinking, self-optimizing grid technologies, as well as certain transmission improvements, physical and cyber security upgrades, and the advanced monitoring and communication capabilities required to enable a smart grid, meet the criteria for the SGTP and will be outlined within the Plans each year as applicable.

Responsive to customers and stakeholders

For grid improvements to be most effective, they must serve the needs of customers. And Duke Energy is working hard to seek out input and better understand the energy needs of customers as it works to build an effective, but flexible modernization strategy for the state.

Through the North Carolina Public Benefits Funds, administered by Advanced Energy and Duke Energy, along with generous technical support from North Carolina's Electric Membership Cooperatives, Duke Energy and Dominion Energy North Carolina, there have been several smart grid stakeholder education initiatives.

As described in the 2016 Smart Grid Technology Plan, Advanced Energy's outreach efforts are being designed to help our state's residents make well-informed energy decisions. They want to share information about new technologies and services when they believe they can offer value, and they also want to share any concerns that may present risk. Highlights of the accomplishments over the past year include:

Collaborative Initiatives

- Duke Energy continued support of multi-year smart grid education and outreach project through the North Carolina Public Benefits Funds, administered by Advanced Energy and Duke Energy, along with generous technical support from North Carolina's Electric Membership Cooperatives, Duke Energy and Dominion Energy North Carolina.

  The goals and objectives of the project are:
  1. To build awareness among key decision makers on relevant smart grid topics and efforts on technology, economic development, and policy across North Carolina.
  2. To educate key decision makers on cross-sector aspects of grid modernization so that they may inform their communities.
  3. To create interesting and informative educational opportunities that brings grid modernization to light in real life situations in communities.
- In 2017, www.NCSmartGrid.org was created as a repository for educational materials and resources developed as part of the body of work. A webinar series was started in 2017 and has continued in 2018 focused on relevant smart grid technology topics. This series provides non-technical government and business stakeholders with a convenient and economical option to learn how smart grid is changing North Carolina's future.

- The tables below depict the interest and participation in these educational resources.

Smart Grid Webinar Series	Attendance
Interconnecting Smart Grid and Economic Development	Scheduled for: October 4, 2018
Grid Resiliency - June 6, 2018	54
Energy Storage - April 26, 2018	63
Self-Optimizing Grid Technologies - October 24, 2017	8
Microgrids and Grid Resiliency - September 20, 2017	15
Smart Meters and AMI - June 22, 2017	39
Solar Power and Grid Integration - May 24, 2017	28
Smart Grid Basics - April 26, 2017	36

	Webinar Recording Plays		
NCSmartGrid.org Activity Log	2017	2018 YTD	Cumulative
Grid Resiliency		27	27
Energy Storage		60	60
Self-Optimizing Grid Technologies	10	25	35
Microgrids and Grid Resiliency	23	24	47
Smart Meters and AMI	51	77	128
Solar Power and Grid Integration	108	30	138
Smart Grid Basics	58	24	82

	Website Page Views		
NCSmartGrid.org Activity Log	2017	2018 YTD	Cumulative
Exploring NC Smart Grid Webpage views	772	484	1256
AMI Case Study Article views	120	100	220
Brunswick AMI Case Study Video - plays	65	27	92
Microgrid Case Study Article - views	94	191	285
Battery Storage Case Study Article - views		162	162
Grid Reliability and Resiliency Article - views		91	91

<u>Duke Energy Initiatives</u>

- Duke Energy facilitated several meetings with NCSEA, Public Staff and other interested parties to discuss guidelines regarding third-party access to customer usage data. On June 21, 2018 Duke Energy filed a report with the Commission in Docket No. E-100, Sub 147 regarding areas of agreement and explanations for points on which agreement was not reached. The results of these discussions are provided in Exhibit 2 – Commission Rules on Third Party Access to Customer Usage Data

- In the settlement agreement approved by the North Carolina Utilities Commission (NCUC) on February 23, 2018, in Docket No. E-2, Sub 1142 for the Duke Energy Progress (DEP) rate case, Duke Energy agreed to "host a technical workshop during the second quarter of 2018 regarding the Company's NC Power/Forward grid investments to explain the need for and ongoing benefits of grid investments, and to hear feedback from stakeholders in attendance". The workshop was held on May 17, 2018. Acting as a neutral facilitator, a team from Rocky Mountain Institute (RMI) convened 65 participants (inclusive of Duke Energy and RMI staff) for a day-long workshop that included content presentations, structured feedback sessions, and facilitated small group breakout sessions. On June 26, the final report for the workshop was filed with the NCUC Docket Nos. E-2, Sub 1142 and E-7, Sub 1146. Duke Energy intends to continue engaging stakeholders to gather input about grid improvement initiatives. The next meeting is scheduled for Q4, 2018.

2. Improving Reliability and Security of the Grid

Reference	Requirement
R8-60.1 (c) 2	*A description of how the proposed smart grid technology plan will improve reliability and security of the grid.*

Our grid is responding to an increasing number of DER interconnections and storms at a time when reliability is more essential to customers and the economy than ever before. Wind and ice storms are two of the leading causes of outage conditions for our power systems, and flooding has also become an increasing concern. Combined with this, the threat of cyber and physical attacks on the grid are real, and of increasing concern.

- On March 15, 2018 the US Department of Homeland Security (DHS) issued a security alert naming Russia as being responsible for attacks on American critical infrastructure. In July, a briefing was held by the DHS indicating hackers exploited relationships between utilities and their private vendors to steal credentials and gain access to the utility networks.
- On April 2, 2018 S&P Global reported that Energy Transfer Partners LP experienced a cyberattack caused an outage in a third-party company's electronic transaction data for its major natural gas pipeline systems, but pipeline operations were unaffected.
- S&P Global reported that Eversource Energy notified customers it experienced a cyberattack in April. The attack also affected Duke Energy and several other utilities. It took down the electronic transaction data interchanges of at least five natural gas pipeline companies.

A growing risk to the system involves the fact that there are cellular modem (telecom transport) devices installed in many of the line devices (Intelligent Line Devices) in the field, which could increase a potential risk to have a bad actor to reach back to our systems through access through the telecom transport device.

For all the new technology projects listed in the Smart Grid Technology Plan under Section 3 through 5, the benefits described, outline the specific impact each project will have on the reliability and security of the grid. Additionally, the investments as a whole will provide synergies resulting in greater overall value in improving grid security, reliability and resiliency, while also creating greater efficiencies and improving safety and sustainability.

3. Current & Scheduled Technology Deployments

Reference	Requirement
R8-60.1 (c) 3	*For all smart grid technologies currently being deployed or scheduled for implementation within the next five years: (i) – (vii)*

Physical and Cyber Security

Distribution line device uplift (CBC, Regular Controls, MVS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Capacitor Bank Controls (CBC) Upgrade

Duke Energy Progress currently has 2,619 switched capacitor bank controllers in service today, a large portion of which have been in service for six to nine years. The current CBC Upgrade project is replacing the 2,101 controllers that were originally installed on the Distribution System Demand Response (DSDR) project between 2009 and 2012.

These devices have been integral in managing the system's reactive power flow during that time. This capability allows the Company to reduce system losses and improve the real power flow capacity on its distribution and transmission system. The implementation of the DSDR program further enhanced the VAR management capabilities of the capacitor bank controls to allow for two-way communications, increased troubleshooting capabilities and automated control of the voltage and reactive power of the distribution system.

The age of the end-of-life capacitor bank controls prohibits providing the needed support due to dated communications and lack of physical and cybersecurity controls of the product. Technology enhancements have deemed these products obsolete and incapable for integration into newly designed control systems. The previous version's obsolescence is exemplified as follows:

- New ethernet protocol schemes employed by cellular service providers do not allow their use
- The integral modems employed use of an older, end-of-life technology that will no longer be supported by the cellular service providers within the next five years

- Door alarms allowing for increased security from physical intrusion of unauthorized parties do not exist
- The manufacturer discontinued the previous version in 2013. The manufacturer has no ability to test or repair, nor do they have any replacement parts remaining for service or repair. If a capacitor bank controller fails, the only option is to replace the control with the new version.

The objective of this program is to systematically replace the obsolete capacitor bank controls with a new version of the equipment and to successfully reintegrate them into the new Distribution Management System (DMS) allowing for continued capabilities of the DSDR program, as well as upgrade the hardware to meet security requirements for grid devices.

Benefits of this uplift effort include:

- Integrated process for implementing EM1, EM2 and DSDR operating modes
- Fully integrated security features which include door alarms allowing for increased security from physical intrusion of unauthorized parties
- Integrated Volt/VAR support allowing Company to maintain voltage support
- Reduced programming support needed to integrate two products into new DMS
- Reduced maintenance efforts needed for aged fleet of controls
- Fully enabled remote access allowing for easy updates of firmware and software enhancements

(ii) The status and timeframe for completion.

The replacement of the obsolete capacitor bank controls with a new version of the equipment is in the planning stages with physical implementation expected to begin in early 2019. Completion of the program including closeout is planned for early 2020.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

Approximately 2,100 capacitor bank controls will be replaced. These controls were originally installed on the DSDR project between 2009 -2012. Duke Energy Progress does not individually track and retire group assets (Distribution and Transmission Line assets) due to the volume of assets on our system. Under group depreciation we assume an asset is fully depreciated when retired, unless it is deemed an abnormal retirement, so it would have a net book value of zero at retirement. When comparing the dollars on this project to the whole balance of 365 assets at DEP which is $1.1B, this would not be considered an abnormal retirement.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

N/A

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

N/A

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
CBC Upgrade	0.000	0.019	1.213	3.000	3.300	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Analysis based on cost effectiveness, functionality and compatibility with existing infrastructure indicates that the new equipment being installed meets all critical requirements.

Secure Access & Device Mgmt. (SADM)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Secure Access and Device Management (SADM) aims to provide a single tool to remotely and securely perform device management activities and event record retrieval on our entire device inventory in transmission and distribution. The project goals are to: Improve the security of devices and increase compliance with NERC CIP and other security requirements, provide process and labor efficiencies associated with device management, and improve post-event resolution.

(ii) The status and timeframe for completion.

The design completion target date is October 2018. Initial infrastructure buildout target date is Q1 2019 and commission complete target date is Q1 2020.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The SADM solution will allow sun setting and decommissioning of locally-purchased solutions in both distribution and transmission. The functionality of the new tool will be new and will replace the need for the existing processes and tools.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

SADM supports internal operations and does not have a customer interface.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

N/A

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
SADM	0.000	0.000	0.182	1.804	0.307	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The goal was to have a single enterprise-wide solution eliminates the need for disparate systems and processes in lieu of a single standard. The project team gathered requirements, determined to purchase instead of internally develop, conducted the RFP processes with multiple vendors, and made selection.

Self-Optimizing Grid

Self-Optimizing Grid (SOG)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Self-Optimizing Grid (SOG) Program implements additional design criteria on distribution circuits that improve reliability and enhances system resiliency. This resiliency will enable the system to reduce outage duration from fault events. Key components of the projects will involve adding capacity to distribution circuits and substations and connecting radial distribution circuits together with automated switches. The head-end enterprise systems such as the self-healing software and the Distribution Management System (DMS) software are essential to enabling this capability.

The SOG is an advancement from “Self-Healing Networks.” The Self-Healing Networks and Feeder Segmentation projects were a foundational step in the progression towards the SOG program. Instead of having individual circuit pairs that can back each other up, the integrated grid network will allow for multiple circuit rerouting options to re-energize segments and minimize customer outage events. The SOG program will further segment the circuits to minimize the number of customers affected by sustained outages and ensures the necessary capacity and connectivity to fully leverage the segmentation.

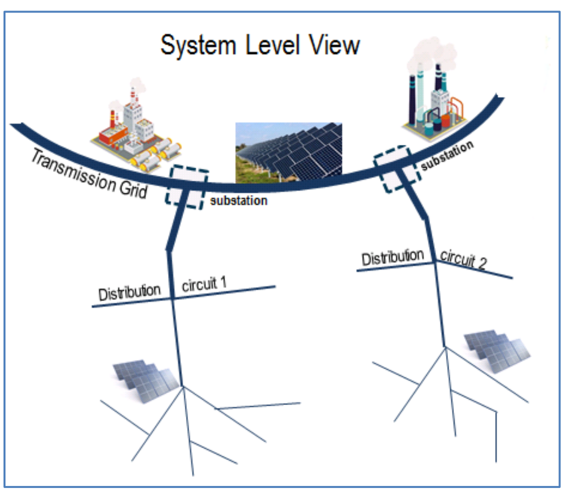
Under this program, circuits will have automated switches deployed according to the SOG guidelines, which outline automated switches approximately every 400 customers, or 3 miles in circuit segment length, or 2 MW peak load. The goal of the SOG program is to have 80% of customers served from circuits that have alternate power re-routing options and sufficient capacity to re-route power without being overloaded the majority of the time. Circuits that meet these additional guidelines will have SOG capabilities.

The SOG will automatically reroute power around a problem area, like an outage caused by a tree falling across a line, animal interference, or other fault events. With this automation, the grid can self-identify problems and isolate affected areas by reconfiguring the circuits, which can shorten or even eliminate outages for many customers.

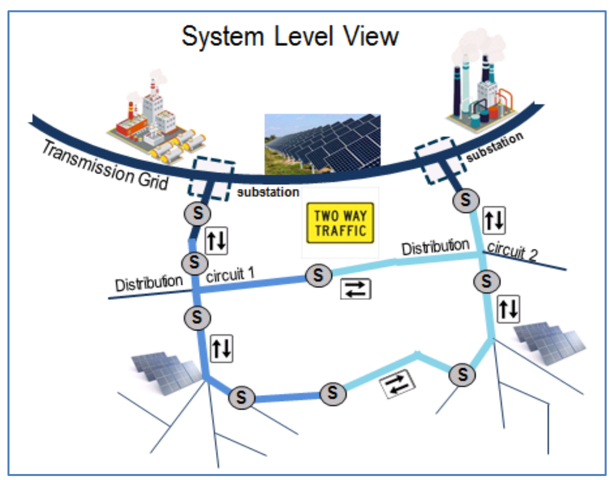
Additionally, these same Self-Optimizing Grid investments and resulting capabilities help the grid to efficiently integrate DER assets (such as roof-top solar) more effectively and efficiently.

- The circuit capacity investments allow for two-way power flow, so that locally-produced DER power can be consumed upstream on adjacent segments within the same circuit
- When that is insufficient, the circuit ties and automation allow the circuit to dynamically reconfigure and allow the DER power to be routed and consumed by adjacent distribution segments and neighborhoods from other nearby circuits

This maximizes the value of DERs and locally-produced power by reducing line losses from transporting that power long distances. SOG's dynamic re-configuration capability routes locally-produced solar to be consumed locally.



Illustrative view of distribution circuits before SOG



Illustrative view of same circuits after SOG

(ii) The status and timeframe for completion.

The initial engineering, scoping and planning for the SOG program began in 2017, and field work began in 2018. The 2018 planning will address work plans for 2020, and the planning for following years will occur as part of the annual planning process. 2018 is the first year of the expected multi-year program to achieve the anticipated goal of 80% of customers being served by the SOG.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

During field work, installations will primarily consist of new equipment to achieve the new SOG guidelines. However, there will be instances where aged, automated switches, or other non-automated equipment will need to be replaced. Automated switch equipment typically has an approximate 20-year expected life, and control and communications equipment, an approximate 5 to 7-year expected life.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable as this technology does not transfer information to/from customers.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this technology does not transfer information to/from customers and will not be utilized by third-parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	Actual	Jan-Jul Actual	Aug-Dec Estimate	Estimate	Estimate	Estimate	Estimate
Project	2017	2018	2018	2019	2020	2021	2022
Automation	2.520	8.297	4.006	21.017	28.363	47.098	72.752
Capacity & Connectivity	9.042	0.238	2.074	24.420	37.092	62.462	97.174

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Self-Optimizing Grid analysis uses the design criteria of segmenting the circuits for approximately 400 customers, 3 miles of circuit, or 2MW of load. Benefits can include:

- Reduces system-wide customers interrupted (CI) and customer minutes of interruption (CMI)
- Creates a networked energy system that improves operational situational awareness
- Minimizes the number of customers impacted by an outage
- Isolates problem areas for quicker mobilization and repair
- Shortens outage duration for impacted customers
- Automates system reconfigurations reducing the need for manual switching
- Improves grid resiliency and ability to recover from major events
- Enables the grid to effectively manage private distributed energy resources

As next generation technologies for switching, protection and controls are identified and vetted via proof of concept testing and business case validation, they will be incorporated into the SOG planning process. Device evaluation will be based on opportunity for enhanced grid capability, increased grid security, or decreased cost.

Advanced Distribution Management System (ADMS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The DMS Consolidation Program is a comprehensive, enterprise-wide program to deploy a common Distribution Management System (DMS) across Duke Energy. Consolidating to a single vendor platform for the DMS and SCADA systems enables operational consistency and efficiency, integrates future solutions, and leverages multiple support teams throughout the enterprise. There are currently three active projects in the DMS Program.

The SCADA Project will upgrade SCADA version 3.1 across Duke Energy. In the DEP service area, the existing SCADA system will be converted to the new common SCADA version 3.1.

The DMS Project will upgrade the common DMS version 3.9 across Duke Energy. In North Carolina specifically, in the DEP service area, the existing DMS will be converted to the new common DMS version 3.7 and then 3.9. Once the new common DMS and SCADA deployment has successfully been completed in the DEP service area, the previous DMS and SCADA will be retired.

The ADMS (OMS) Project will install the ADMS Outage Management functions cross Duke Energy to a common version 3.9. In North Carolina specifically, this will allow the operators to leverage one geographic view for managing the grid and outages. Implementing a common platform across all service territories will support standardized operations. This will allow more rapid response during high impact events by reducing learning curve for shared resources. In addition, a consolidated DMS and OMS reduces system complexity and cost to maintain.

(ii) The status and timeframe for completion.

	2015	2016	2017	2018	2019	2020	2021
DMS 3.7	Start Date					Close Date	
DEC	Q4					Q1	
		Start Date				Close Date	
DEP		Q1				Q1	
SCADA 3.1				Start Date		Close Date	
DEC				Q3		Q1	

		Start Date				Close Date	
DEP		Q3				Q1	
ADMS				Start Date			Close Date
DEC				Q1			Q4
				Start Date			Close Date
DEP				Q1			Q4

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The DMS and SCADA conversion will replace existing computer hardware. The replaced hardware (servers and server support equipment) will be repurposed and reused within the company for other projects.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable as this project does not involve the transfer of customer information.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not involve the transfer of customer information.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

ADMS Consolidation Program Costs

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
SCADA	2.163	2.950	1.920	1.943	1.497	1.007	0.000	0.000
DMS (3.5)	2.101	6.836	3.014	4.048	1.141	0.768	0.000	0.000
OMS (ADMS)	0.065	1.680	1.913	4.084	5.154	5.895	7.020	4.581
Total	**4.329**	**11.466**	**6.847**	**10.075**	**7.792**	**7.670**	**7.020**	**4.581**

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The DMS Consolidation Program supports the overall vision of Duke Energy to move to a single vendor platform for DMS and SCADA by scaling common platforms to all locations in one coordinated program.

Enterprise wide, quantifiable benefits expected from the DMS consolidation are approximately $4M annually once the system is fully deployed. These savings are primarily driven by the elimination of costs associated with annual vendor support and maintenance contracts, upgrades, and issue resolution costs for multiple control system vendors, as well as an anticipated reduction in internal maintenance and support required for multiple control system vendors. Some of the additional, non-quantifiable benefits include:

- Improved reliability of the distribution system
- Near real time (every 15 minutes or by exception) power flow calculations of the entire distribution network
- Fault location, isolation, and service restoration
- Switching plan formulation, validation, and execution
- Linkage to the Energy Management System on the state of the distribution network
- Functionality to meet peak shaving requirements through DEP EE/DSM programs
- Platform for integration of distributed renewable power sources within the distribution grid
- Remote Distribution Control Center (DCC) monitoring and control of station and field devices
- Alarming capability to issue alarms based on operational conditions to notify DCC operators of changes in system or device conditions
- Capability to electronically tag field devices for safety and informational purposes
- Substation graphical dashboard monitoring and control capabilities
- Emergency load shed functionality including surgical load shed capability
- Framework to standardize processes and operations across the enterprise
- Trend and forecast visualization
- Cold load pickup improvements, reducing outage time

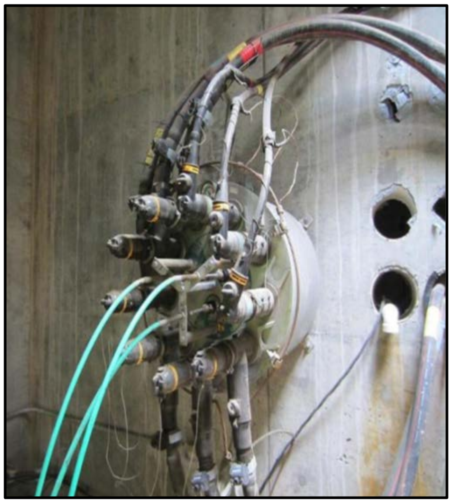
Distribution System Modernization, Automation and Intelligence

Urban Underground Automation

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Urban Underground Automation DEP Program is Duke Energy’s full Carolinas installation of an underground distributed intelligence loop distribution automation system. This type of system is installed in locations where load reliability can have a direct impact on safety, such as a downtown or dense multi-use location, or other high-profile places, like airports, stadiums, etc. Restoration times for this system allow isolation of events in seconds, with the system not dependent on communications to a centralized head-end solution. Instead, the system is able to make independent decisions and control actions within the distributed loop.

This program will provide visibility and automation to the vaults in urban areas by integrating the distributed automation control system into the existing Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS) through a fiber optic communication network. This program has unique challenges because the equipment is housed in underground vaults and not on the overhead distribution system.



Current Vault

Future-state Vault

Similar to Self-Healing Networks, this technology responds to a loss of power by utilizing real time data from intelligent sensors to isolate faults, reroute the power supply around the fault, and return power to as many customers as possible until the problem area is repaired. In most cases, this entire process occurs in seconds. In fact, most of the customers who would have lost power for at least 45 minutes with the current system will only experience a momentary interruption, or an outage of less than one minute.

(ii) The status and timeframe for completion.

This program is currently in the planning phase for 2018 as we use lessons learned from the pilot project. The pilot project will close in Q3 2018. The installation for the program will begin in Q2 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

Switchgear containing SF6 gas will be replaced, resulting in a significant environmental improvement.

- Live front switchgear, terminations, etc.
- Legacy SF6 switchgear.
- Manually operated switchgear that cannot be retrofitted for remote operation.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

($ in thousands)	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
UUA	0.00	0.00	0.089	0.153	1.370	3.270	8.030	8.260

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Key learnings derived from the Urban Underground & Automation Raleigh Pre-Scale deployment included:

- Centralized communications being more preferable than peer-to-peer communications for outage restoration.
- Strict uniformity regarding document control (e.g., software upgrades, firmware versions, etc.)
- Telecommunications infrastructure standards for similarly deployed switching hardware.

Benefits of this technology confirmed during the Urban Underground & Automation Raleigh Pre-Scale Deployment project included the following:

- Safety through minimizing the need for workers inside of the underground vaults, reduced power interruptions, minimizing the number of impacted customers to only those on the affected segment of the underground circuit.
- Reduced restoration time due to self-healing scheme / elimination of recordable outages. All customers would be restored for interruption of a single electrical source in seconds versus a 45-minute minimum outage for responding crews.
- Improved asset utilization provides real time data and control of system, a functionality which does not exist today.
- Enabled ability to do planned switching
- Flexibility of additional switching points being added to system with proposed relay scheme to handle continued rapid growth in high density zones

- Enhanced monitoring and maintenance of assets, including enablement of monitoring and control of auxiliary systems (sump pumps, transformer oil level and fan operation, static infrared cameras)
- Power quality, enables planning and load growth data.

Enterprise Distribution System Health Tool

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objectives of the enterprise distribution system health (EDSH) tool are to create an analytic model with actionable circuit – level information on reliability CSAT, Asset, and Vegetation for use by planning to provide a basis for prioritizing work to achieve the highest possible benefits in terms of customer reliability and cost reduction. The scope of the project consists of developing a platform using SAS tools and web-based user interface using Visual Analytics that can display corridor and/or protective-device level information; identify circuit and device level areas for analysis, attention and investment, and identify circuits that require incremental work. Business processes and change management is also included. The asset has a life expectancy of 5 years.

(ii) The status and timeframe for completion.

This project was initiated in 2016. The EDSH v1 Go-Live was in Q2 2016 and v2 Go-Live was in Q4 2017. The v3 Go-Live target is scheduled for Q1 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This is a new application for Duke Energy

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul estimate	Aug-Dec estimate	estimate	estimate	estimate	estimate

Project	2016	2017	2018	2018	2019	2020	2021	2022
EDSH	0.100	0.243	0.120	0.246	0.114	0.000	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses

Analysis mostly included identification of the benefits of this system.

- Reduce capital by extending life of assets.
- Reduce O&M by condition based maintenance or data driven maintenance schedule.
- Optimizing maintenance programs based on analytic scenarios (e.g. vegetation, maintenance program)
- Improving real-time operations from analytic insights (e.g.; outage durations, response for maintenance and restoration)
- Enable the retrieval of data, analytics insights and system status in a more efficient manner.
- Provide grid investments vegetation and other asset management data in an efficient manner to assist with the selection, prioritization and management of the Targeted Underground initiative.

Transmission System Modernization, Automation and Intelligence

Upgrade electromechanical relays to digital/electronic

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The intent of this System Reliability Program (SRP) is to systematically replace all Electromechanical and Solid State relays, both Transmission and Distribution class, for all elements (line terminal, bus, transformer, breaker failure, etc.).

These relays have been installed as far back as 1960 and are well beyond the end of their useful life. A majority of the line relays were installed in the early 1970s, which still exceed the relays' useful life of 30 years according to EPRI's "Protection Equipment Asset Management Analytics Development" for relays designed with cylinder units with capacitors. Solid State relays have a significant number of electronic components with a definite life, which is shorter than electromechanical relays.

Technology used in the protection and control industry has changed from electromechanical to solid state to microprocessor-based platforms. This change in technology has also increased the use and sophistication of various communication protocols and media. The need for more device functionality has accelerated because of the following factors:

- More demanding regulatory requirements
- Advances in technology

- Demand for operational data
- Demand for increased performance and reliability

The deployment of microprocessor-based protection system provides the following benefits:

- Flexibility in operating the system
- Improved fault-location capabilities
- Supports reduced outage restoration times
- Additional data available about the performance of the system and reliability insights

(ii) The status and timeframe for completion.

Replacement of electromechanical and solid state devices has been ongoing for many years. The program will be reviewed and executed over a 5-year period, after which the program will be re-evaluated for continued execution.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The electromechanical and solid state relays being replaced will be rendered obsolete with no expected salvage value or alternative uses.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section in not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul estimate	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Digital Relay				0.000	7.875	9.625	22.700

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Installations are determined by location of the assets within scope of the program. Several factors are evaluated to determine priority of replacement including, but not limited to: performance history, location criticality, customer sensitivity, additional scheduled capital work at specific locations, and preventive maintenance due.

Remote Control Switches

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Transmission SCADA technology includes the deployment of remote control capabilities to existing switches, or in some cases net new switches that include remote control capability. This technology provides additional flexibility to the system operator in order to configure the system as necessary and vastly increases the resiliency of the Transmission grid. This additional capability supports increased capabilities to isolate equipment for maintenance purposes as well as isolate failed or damaged equipment during events. Remote switching capability can decrease restoration times following outages thus minimizing disruption to customers. This capability being widely enhanced across the service territory also provides increased capabilities during significant storm events to be able to isolate impacted areas and increase the ability to rapidly restore service to a larger portion of customers.

(ii) The status and timeframe for completion.

The Company aims to substantially advance this program that systematically identifies new locations to add remote control capabilities to existing switches, or net new switches with remote control capabilities are determined. The program will be reviewed and executed over a 5-year period, after which the program will be re-evaluated for continued execution.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

No existing equipment is expected to be rendered obsolete by the new technology, unless an existing switch is completely replaced during a project due to poor asset health. In this instance there would be no salvage value of the obsolete equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The technology does not contain any information that would be collected or shared with customers.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

The technology does not contain any information that would be transferred to, or used by, third parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in Millions	actual	Jan-Jul estimate	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Control Switches				0.193	1.178	2.463	3.563
SCADA Installations				0.000	0.285	0.285	0.285

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Installations are determined with consideration to several factors used to determine priority including, but not limited to: operational and performance history, location criticality, customer sensitivity, number of customers served, line and system configuration, additional scheduled capital work at specific locations, and exposure of line section length.

Condition-Based Monitoring (CBM)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Condition-Based Monitoring (CBM) program will install new monitoring technology. The CBM system consists of online transformer monitoring for key parameters to allow operations staff to continuously assess the condition of a transformer and its bushings from locations remote to the substation. The system will be installed on transformers throughout the Duke Energy system based on each transformer's criticality to the system, its condition, age, and known operational issues that can impact the transformer's reliability and availability. The monitoring system consists of a commercially available multi-gas monitor and moisture monitor for the main tank of the transformer, a multi gas monitor for the tap changer compartment for load tap changing transformers (LTCs), a bushing monitor system, and a communication system for collecting the data and integrating it into the enterprise system.

(ii) The status and timeframe for completion.

Full deployment is expected to start Q4 2018 with approximately 10 sites per year for the next 5 years.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

There is no existing equipment being removed. The project is adding monitors to transformers to remotely monitor the health of the transformer.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec actual	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
Pre-Scale	0.00	0.272	0.00					
Full-Scale			0.00	0.585	2.115	2.115	2.115	2.115

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The sensor technology selected was informed by a pre-scale project that occurred at Duke Energy in 2016 and 2017. The projected benefits of an online transformer monitoring system are as follows:

- System Monitoring – The monitoring system will provide real-time information on system and component condition.
- Reliability Improvement – The early warning offered by a transformer monitoring system can lower the risk of an unscheduled outage, and minimize the severity and duration of the problem through early identification.
- Defer capital investment of existing transformers.
- Avoidance of the potential environmental impacts associated with transformer failures. Catastrophic transformer failures (of types that could potentially have been detected by the proposed monitoring system) release oil into the substations and the surrounding areas.
- O&M Cost Management – Routine diagnostic tests such as oil sampling and off-line bushing tests can either have their intervals extended or eliminated for those transformers that have the monitoring system. Manual oil sampling and off-line bushing power factor tests will be performed when the monitoring system indicates a significant change in operating condition.

Phasor Measurement Units

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

A Phasor Measurement Unit (PMU) provides real-time stamped voltage and current phasor information that can be utilized to determine the system stability and health of an electrical network. The phasor information, by definition, contains the voltage and current amplitudes as well as the phase angle for each to allow for the determination of their state based on the time stamp. Observation and analysis of multiple samples of phasor data is conducted to detect shifts in the frequency of the voltages and currents which may indicate aberrant conditions on the electrical network, even down to the cycle level.

Utilizing multiple samples across a wide-area grid allows for the early detection of conditions that could impact the grid. PMUs provide the following benefits:

- Optimizing situational awareness, system state estimation, and security monitoring
- Improving the reliability of the transmission power system
- Implementing the capability to understand system reactions and interactions at a deeper level
- Providing communication capabilities to support transmission resources
- Providing upgraded secure communications from Duke Energy to the transmission substations
- Preparing the transmission network for distributed renewable power sources
- Modernizing the grid by eliminating communications bottlenecks and increasing bandwidth capacity across the network

(ii) The status and timeframe for completion.

This project installed 14 PMUs across seven sites in 2016, 25 PMUs across 14 sites in 2017, and will install five PMUs across three sites in 2018. This project will close in Q1 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

No equipment is being rendered obsolete of this project.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable as this project does not involve the transfer of customer information.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not currently involve the transfer of customer information to any third-parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

Total capital costs are planned to be approximately $1.5 million.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
PMU	0.5	0.6	0.4	0.0	0.0	0.0	0.0	0.0

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

- Phase measurements taken at strategic locations throughout the grid, such as at large bulk power switching stations, allow for holistic overview of the "heartbeat health" of the grid.
- Other key locations for identification include key generating points, major utility interconnections, and radial isolated portions of the bulk power grid where power flows may cause specific power balancing conditions.

Phasor NXT

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

PMUs are a key component of Transmission's long term vision. Duke Energy is committed to the deployment of PMUs across the enterprise. The GS PhasorNXT project will support this vision by providing the software required to support the PMUs, and leverage the PMU data for system visibility, state estimation and post event analysis. PhasorNXT is a comprehensive platform that integrates synchrophasor-based linear state estimation and real-time wide-area visualization technology to provide a state of the art synchrophasor monitoring platform. PhasorNXT will deliver to operators improved synchrophasor data quality, expanded visibility beyond available PMUs by calculating virtual PMU values, state estimated values based on *e*LSE (*enhanced* Linear State Estimation), one-line diagrams and visualization for situational awareness monitoring using RTDMS. Operators will have the ability to view the system geographically via PhasorNXT Visualization Client displays, or using the one-line diagrams with zoom in capability.

(ii) The status and timeframe for completion.

The project is expected to be completed in Q4 2018.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable. The project installs new servers only.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
Phasor NXT	0.00	0.040	0.026	0.081	0.000	0.000	0.000	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The analyses for Phasor NXT is primarily part of the PMU Project. Pertaining to the PhasorNXT software, multiple instances were needed due to NERC CIP Architecture Policies and the need to align the instances to the various jurisdictional ECC's and the ECC practice where all apps reside within a 6-walled data centers.

Transmission Health and Risk Management

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objective of the Health Risk Management (HRM) is to extend the lifecycle of aging assets, in particular transformers, and reduce the risk of asset failures that can lead to outages by shifting from a reactive to a proactive/predictive model by utilizing component, asset, fleet, and system health and risk data. A new HRM platform for collecting and analyzing data will be implemented.

(ii) The status and timeframe for completion.

Planning for this project began Q4 2016 and ended Q4 2017 when the project was approved. The design phase took place from Q4 2017 through Q1 2018. The initial Go-Live date which will include transformer data is Q1 2019 for DEP. The Go-Live date for circuit breaker data is Q2 2020 for DEP.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This is a new application for Duke Energy.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2016	2017	2018	2018	2019	2020	2021	2022
HRM	0.000	2.077	0.634	0.398	1.474	0.836	0.627	0.000

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Benefits expected from the implementation of the Transmission HRM system include:

- Reduction in Emergent and Emergency Transformer/Equipment Replacements leading to cost saving
- Deferral/improvement in capital efficiency through predictive intelligent asset management
- Extend the lifecycle of the aging assets
- Use dynamic automated watch lists
- Shift from reactive to proactive asset management
- Improve Asset Visibility and reporting across the enterprise
- Improvement of capital and O&M, managing incremental costs with asset growth
- Providing fleet level risk indices
- Decrease Emergent and Emergency Truck Rolls

Overall Savings due to personnel operational efficiencies:

- Ability to capture within a system asset knowledge

- Elimination of manual efforts
- Decrease in emergency and emergent call outs
- Prioritizing Projects and Maintenance
- Prioritizing Replacements and Maintenance
- Remote access to equipment data and analytics

Predictive asset health and risk driven work schedules, as opposed to calendar based schedules:

- DGA Testing w/ DGA Monitors in place
- CB I2T loss, breaker wear w/ CB Monitors in place
- Power Factor testing w/ Bushing Monitors in place

Reduction in SAIDI

Communications

Grid/Business Wide Area Network – Core/Edge Network Uplift

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Today, DEP uses large carrier grade routers to serve as the core networks for its Grid and Business wide area networks (WAN). The DEP Grid and Business WANs are physically separate networks. The DEP Grid WAN provides network connectivity to DEP substations. Data network equipment such as routers and switches is deployed at the DEP substations for termination of the Grid WAN connections. The Grid WAN core routers are located at major Telecom communication hubs throughout the DEP service territory, including the energy control centers where the head-end SCADA systems reside. The combination of the core and substation routers make up the DEP Grid WAN, which enables the DEP SCADA systems and other grid applications to monitor, control and manage the electrical grid assets and network.

The DEP Business WAN utilizes a separate set of large carrier grade routers to provide network connectivity for DEP facilities that need to access business specific or enterprise applications, physical security systems, and telephony and radio systems. The DEP sites that leverage the Business WAN include Transmission and Distribution Operations Centers, Power Plants, Energy Control Centers, Data Centers, Customer Call Centers and Regional Corporate offices. Edge routers and switches are deployed at these facilities for termination of the Business WAN connections.

The DEP Network Uplift initiative includes efforts to replace end of life data network equipment used on the DEP Grid and Business Core WANs, and deployed in DEP substations and Transmission and Distribution operations facilities. The end of life data network hardware will be replaced with current technology. The Core WAN is being redesigned and may result in consolidating the two separate Grid and Business networks in place today with a single network with virtual capabilities to segment and secure different types of network traffic. This change will improve operational efficiency of the Core network, while still maintaining the levels of security needed for Grid and Business communications.

The DEP Network Uplift initiative also includes implementing a feature called Dynamic Multipoint Virtual Private Network (DMVPN) to improve automated rerouting of substation SCADA traffic due to various network outage scenarios. Secondary or back-up network connections such as cellular are needed for DMVPN; therefore, these projects will add secondary connections where needed.

All data network equipment (routers and switches) have an expected average life of 5 – 7 years.

(ii) The status and timeframe for completion.

The projects in the DEP Network Uplift initiative are a complex undertaking starting in 2018 and will take 3-5 years to complete. However, the duration of the project may change depending on the final design, ability to schedule outages, and availability of resources and funding.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The equipment that is being replaced by the DEP Network Uplift initiative includes core and edge routers and switches. The full list of equipment being replaced in DEP will be identified and documented during the projects. The anticipated book and salvage values of this equipment at time of retirement will be $0, and there is no alternative use for this equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The DEP Grid and Business networks are implemented solely for conducting internal Duke Energy business. The DEP Grid Core/Edge network, which is a dedicated and secure network, is not used to transfer data between Duke and its customers. The Business WAN core is also a dedicated and secure network that mainly provides connectivity for internal DEP facilities.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

Duke Energy may contract with third parties to provide engineering and/or installation services for the DEP Network Uplift projects. Third parties would not have access to the DEP Grid and Business networks after their work is complete. Third parties will not have access to customer-specific information during their work and after their work is complete.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

($ in thousands)	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022

DEP GridWAN / BizWAN Network Upgrades	0.000	0.105	1.587	8.584	5.218	5.039	1.759

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The current DEP Core network router technology has reached manufacturer end of life and is currently experiencing some reliability issues, thus creating a need to replace the current hardware to maintain operational reliability of the Grid and Business networks. Duke Energy Telecom created a request for proposal (RFP) in 2017 and distributed it to several network vendors. The purpose of this RFP was to seek solutions for redesigning the Grid and Business WAN core networks, and replace the end of life hardware with new technology and functionality. The design phase will determine what hardware and features are needed and where equipment will be installed. Additionally, edge network hardware (routers and switches) at Grid (substations) and Business facilities will be replaced with current Telecom equipment standards at the point they are deemed to have reached their end of life. The DMVPN technology for the DEP Grid WAN is being deployed based on new Duke Energy Telecom standards to improve reliability and resiliency of substation communications.

Next Generation Cellular

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

A significant number of the cellular connections at Duke are on cellular 2G/3G networks that are end of life. Duke Energy is working with the cellular carriers to transition these connections to their LTE networks. The Next Generation Cellular initiative will replace existing legacy 2G/3G cellular modems for DEP distribution line devices and substations. These modems, which have exceeded their life expectancy of 3 – 5 years, will be replaced with 4G modems, and 5G modems when available. The current 4G and future 5G cellular technologies provide greater network bandwidth or throughput, lower latency or response time, and better cybersecurity protections. The new 4G and 5G modems will also have a life expectancy of 3 – 5 years.

(ii) The status and timeframe for completion.

The Next Generation Cellular effort started in 2017 and will continue through the end of 2022.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The 2G/3G cellular modems being replaced were installed in 2012 and prior years. The anticipated book and salvage values of this equipment at time of retirement will be $0, and there is no alternative use for this equipment.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Cellular communications for DEP Grid substations and Distribution line devices are not used to transfer data between Duke Energy and its customers. These network connections, which are implemented solely for conducting internal Duke Energy business, are secured in accordance with Duke Energy Cybersecurity standards.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

Duke Energy will use internal resources to engineer and install new the new 4G/5G modems for the DEP Next Generation Cellular effort. Third parties may be used to assist in configuration of the new modems prior to activating them on the cellular network, or installing and commissioning them in the field. Third parties will not have access to customer-specific information during and after their work is complete.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

($ in thousands)

	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
DEP Next Gen Cell Modems	0.130	0.446	0.249	0.780	1.472	1.703	0.322

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Replacement of the 2G/3G modems is required because carrier 2G/3G cellular networks are end of life. Modems that are targeted for replacement were identified through a review of Duke Energy and carrier asset inventory data. The hardware chosen to replace the 2G/3G modems is based on current Duke Energy cellular modem standards.

Strategic Fiber & Wireless Transport

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Strategic Fiber & Wireless Transport initiative provides for the end of life replacement of Duke Energy privately owned fiber and wireless transport systems. These systems are the backbone of Duke Energy's private network, providing Grid and Business network connectivity to DEP substations, operations facilities, energy control centers, generation plants, customer call centers, data centers and corporate offices. Most of Duke Energy's internal Grid and Business functions traverse its fiber and wireless transport systems. Replacement of these end of life systems is needed to improve network reliability and resiliency, increase data network capacity, support changing security requirements, reduce O&M expenses, and foster technology transformation. The table below describes several work streams within the Strategic Fiber and Wireless Transport initiative that improve Duke Energy's backbone communications infrastructure.

Technology	Description	Expected Life Cycle
Fiber optic cable	The backbone of Duke Energy's communications network (a.k.a. the 3rd Grid) is the transport network, which consists of fiber optical cable and microwave systems. A recent current state assessment identified 1,750 miles of fiber optic cable that needs to be evaluated for replacement based on age and performance. Much of this fiber has already reached or exceeded its typical industry life cycle of 20 – 30 years, depending on the fiber type, application and installation location. New fiber cabling will have a similar life cycle. Additionally, Duke Energy will expand its fiber network to connect key generating plants, operations centers, substations and other critical facilities to satisfy business needs identified during the Enterprise Communications Strategy effort. The Fiber Optic Cable work stream has begun replacing end-of-life fiber optic cable and constructing new fiber routes based on business needs. This work stream is also investigating alternatives to using optical ground wire (OPGW) to enable Duke Energy to deploy fiber faster and less costly.	Typical life cycle of fiber optic cable is 20 – 30 years.
Microwave	Like fiber, microwave provides high capacity connectivity to the core Duke Energy communications network. Much of the current microwave uses obsolete TDM technology, with capacity that is not meeting current business needs. Microwave is an important part of the Duke Energy transport network as it provides high speed connectivity in areas where installing fiber is not economically feasible. Many of Duke Energy's microwave systems in place today are end of life and manufactured discontinued, or are not meeting business capacity needs. These systems will be replaced with Nokia equipment, which is Duke's current MW radio standard.	Typical life cycle of microwave radio systems is 10 years.

Technology	Description	Expected Life Cycle
Optical systems	Optical systems are the electronic systems that "light" the fiber optic cable and send signals through the fiber optic cable for communications. Much of Duke Energy's optical systems use SONET/TDM technology, which is becoming obsolete and manufactured discontinued. The five-year technology plan has identified optical nodes that will need to be replaced, removing SONET/TDM systems and installing the latest packet-based technology that provide more capacity. Duke Energy will be installing new optical equipment that will position Duke Energy for the next 10 years of bandwidth expansion and modernized IP/Ethernet services.	Typical life cycle of optical systems is 10 years.
MAS Radio	Multiple Address System or MAS are radios that provide "last mile" wireless connectivity for substations. MAS technology is a low speed/low bandwidth system that is typically suited for serial data connections to low speed SCADA devices. Much of Duke Energy's MAS radios are end of life and manufactured discontinued, and will be replaced by newer technology, such as the point-to-point and point-to-multipoint radios.	Typical life cycle of radio transport systems is 10 years.
Tower and Shelters	Many of Duke Energy's communications towers, shelters and DC power systems must be replaced due to age, structural issues and capacity. Duke Energy is planning to replace towers, shelters and DC power systems in multiple locations across its entire service area. The Tower and Shelter Replacement project will address all facets of the tower and shelter work, including initial inspection, engineering, regulatory work, obtaining right of ways, completing construction and performing final inspection.	Typical life cycle of communications towers is 40 – 50 years, depending on environmental conditions, weather, preventive maintenance and tower loading. Typical life cycle of communication shelters or buildings is 25 – 30 years, depending on environmental conditions, weather and preventive maintenance. Typical life cycle of

Technology	Description	Expected Life Cycle
		DC power systems is 7 – 10 years; however, batteries are typically replaced about every 5 years.

(ii) The status and timeframe for completion.

The Strategic Fiber and Wireless Transport work streams in DEP are underway and will continue for the next 10 years.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The fiber optic cabling, optical systems, microwave systems, communication towers, communication shelters and DC power systems and batteries that will be decommissioned during this work stream will be rendered obsolete by the new technology installed. The anticipated book and salvage values of this equipment and hardware is anticipated to be $0. Some of the optical and microwave electronics may be used as spare parts in the interim until all related systems have been removed from service.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Duke Energy private fiber and wireless transport systems are not used to transfer data between Duke and its customers. These systems are implemented solely for conducting internal Duke Energy business.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

Duke Energy may use third parties to assist in design and construction of fiber optic cabling, optical systems, microwave systems, DC power systems and MAS radio replacements. Duke Energy will use third parties to replace communication towers and shelters. Third parties will not have access to customer-specific information during and after their work is complete.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

($ in thousands)

	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
DEP Fiber Optic Cable	0.170	0.006	0.350	2.674	10.593	10.519	$11.203
DEP Microwave Systems	0.000	0.263	0.000	0.156	0.618	0.613	0.653
DEP Optical Systems	0.000	0.000	0.000	0.218	0.864	0.858	0.914

DEP MAS Radios	0.000	0.208	0.083	0.587	2.326	2.309	2.460
DEP Tower and Shelters	0.113	1.854	1.662	3.621	2.667	2.638	2.478
Total							

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Phase 1 of the 2016 Enterprise Communications Strategy effort consisted of current state analysis of the Duke Energy Telecommunications network. The project team determined that much of the systems, equipment and physical infrastructure of Duke's backbone network was at or near end of life, or facing constraints on network capacity that was impacting business performance and reliability. The Strategic Fiber and Wireless Transport initiative was established to address these end of life, capacity and reliability issues associated with fiber optic cable, optical systems, microwave radio systems, MAS technology, and communication towers, shelters and DC power systems. Duke Energy Telecom will replace obsolete equipment, systems and hardware with current standards. Where necessary, Duke Energy Telecom will create RFP's to evaluate new technology, equipment, systems, hardware or vendors and select the most appropriate and cost-effective path for replacement. Duke Energy has already utilized the RFP approach to make technology decisions for new optical systems, microwave radio systems and MAS replacements. Telecom also used the RFP process to select vendors to replace communication towers and shelter.

Energy Storage

Energy Storage Projects (Asheville – Rock Hill Battery Energy Storage System and Hot Springs Microgrid)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

As part of the Western Carolinas Modernization Project (WCMP), DEP identified opportunities to deploy over 50 MW of battery projects throughout the region, including an approximately 9 MW lithium-based battery interconnected to the Asheville – Rock Hill Substation in Buncombe County, North Carolina and an approximately 2MW solar PV facility and 4 MW lithum-based battery interconnected to the Hot Springs distribution feeder in Madison County, NC. Major components will include solar panels, battery cells, management systems, power conversion systems, and associated interconnection equipment. The primary use of the projects is to provide capacity during system peaks and for future load increases as well as backup power to customers. The projects may also provide essential reliability services, such as frequency, voltage, and ramping support, to the electric grid. The expected life of the projects is approximately 25 years.

(ii) The status and timeframe for completion.

DEP expects to complete construction of both projects in 2019 or 2020.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

None. The projects will be installed in lieu of performing traditional upgrades at these locations.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

While the technology is not intended to transfer information directly between it and utility customers, the utility continues to engage with the local community on technology-related items. Members of the local community include the Energy Innovation Task Force (EITF), which is the advisory and innovation group of community leaders co-convened by the City of Asheville, Buncombe County, and Duke Energy.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not currently involve the transfer of customer information to any third-parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

Depending on the final designs, the cost estimate for each project is between $10-20M with a significant portion of the capital expenditures expected in 2019.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses

The projects were identified during distribution planning optimal sites for a system-wide battery deployment plan that would meet the Commission's order and the goals and objectives of the WCMP.

Energy Storage Control System

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Energy Storage Control System (ESCS) Project scope develops and deploys a battery storage Head End monitoring and control system for remote access and control to every grid scale, grid connected battery storage site deployed by Duke Energy. The Head End will provide monitoring of operations and health conditions information to multiple groups and an overview of battery storage operations across the entire Duke Energy grid. The Head End software will provide individual or aggregated battery site remote control, as needed, to alter battery use schedules or operational parameters for changing business needs. The

Head End will also enable the aggregated use of battery storage sites for local or bulk energy support in the near future.

The Project deliverables include the software solution for monitoring and operations required for both storage and solar-plus-storage energy business use cases. The primary control applications will include:

- Frequency Regulation support for Duke Generation
- Energy Arbitrage – shifting energy use (charge off peak, discharge on peak)
- Grid Islanding for outage support and peak shaving

The ESCS software will also provide battery storage system health and operations monitoring functions including:

- Substation Load Monitoring to avoid asset overload condition
- Battery System Operations Monitoring, Alarming & Remote Notification
- Cycle Maintenance Management – Maintenance per component (battery system, HVAC, Inverter)

.(ii) The status and timeframe for completion.

Vendor selection, project planning and contract development for the ESCS Project began in January 2018. The in-service date is expected to be in late 2019.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

The project does not replace any systems or equipment currently in place.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
ESCS	N/A	0.063	0 .530	0.853	0.135	0.135	0.068

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

Duke Energy submitted a Request for Information (RFI) mid-2017 to 18 software suppliers that provide control systems for battery storage. Duke reviewed each vendor submitted proposal and ranked each supplier according to their written response. From this evaluation the sub-team selected a short-list of suppliers. An RFP was issued to the three short-list suppliers in November 2017. The sub-team evaluated each RFP submission and held face to face interviews and system demonstration with each supplier. The sub-team further scored each supplier from these RFP sessions and selected a preferred supplier to carry into contract negotiations.

AMI

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Advanced Metering Infrastructure (AMI) is the foundational investment that will enable enhanced customer solutions - giving customers greater control, convenience and choice over their energy usage, while also giving customers the opportunity to budget, save time and save money. AMI technology allows a utility to gather more granular usage data and utilize new capabilities to offer new programs and services to customers that are not achievable through existing meters. The AMI technology will pave the way for programs that will allow customers to stay better informed during outages, control their payment due dates, avoid deposits, to be reconnected faster, and to better understand and take control of their energy usage, and ultimately, their bills. The Company also expects AMI meters to result in reduced truck rolls with remote capabilities to operate internal switch for majority of meters.

Deployment of smart meters allows customers to start, stop and move service without the need for a technician visit. The smart meters also provide an interface for customers to see and understand their hourly energy usage, allowing them to better manage their consumption and, as a result, their bills. Smart meters have enabled current customer programs such as net metering and mid-billing cycle usage alerts and help enable future customer programs such as outage notification alerts, a real-time usage application for smart phones, and the ability for customers to select their payment due date. The technology can also help enable future energy efficiency options and potential time-of-use rate offerings as well as pre-payment programs.

The new smart meters are directly interoperable with the existing AMI systems and will be depreciated over a period of 17 years pursuant to the terms set forth in the Company's last rate case proceeding Order entered February 23, 2018 in Docket No. E-2 Sub 1142.

(ii) The status and timeframe for completion.

Deployment began in May 2018. Through August 2018, DEP has installed a total of approximately 121,596 smart meters in NC. DEP NC plans to install a total of approximately 1,267,462 meters through 2021.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

DEP expects to replace approximately 1,199,675 million Automated Meter Reading (AMR or “drive-by”) meters, 52,018 older smart meters, and 15,769 walk-by meters over the four-year period that began in May 2018 and ending in 2021. The remaining net book value of the meters being removed is approximately $68.7M as of December 31, 2017

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

Smart meters capture energy usage and send it to grid routers directly or through range extenders and/or other meters to form a radio frequency (RF) mesh network, or via cellular Direct Connect. The grid routers transmit collected usage data to the AMI headend system via cellular backhaul once each day. The head-end system acts as the data collection point inbound from the metering infrastructure, as well as providing meter command and encryption key management outbound. The data is then sent to a Meter Data Management (MDM) system which provides billing determinants to the customer billing system for billing.

The data collected by the AMI meter utilizes a unique meter number (not displayed on the meter face) and thereby contains no personally identifiable customer information. All data is encrypted at the meter and decrypted at head-end system. The meter number is then used as the linkage to other information within the customer billing systems.

See SGTP Exhibit 2 - Commission’s Rules on Third Party Access to Customer Usage Data for additional information and Appendix B related to how the utility provides usage information to customers through the secure online customer portal and billing statements.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable as this project does not currently involve the transfer of customer information to any third-parties. Refer to Exhibit 2 for general information on providing data to customers and third parties.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

DEP has incurred approximately $43.6 million of actual capital expenditures on the AMI project through August 2018. Based on the most recent cost estimate for the project, the forecast capital costs are outlined below:

DEP AMI Capital Forecast (NC and SC)	Inception to date (actual)	Sept-Dec 2018 (estimate)	2019 (estimate)
Annual Capital $ (millions)	$43,634,256	$31,311,047	$91,876,319

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

The Cost-Benefit Analysis attached as Appendix C, Exhibit A to DEP's 2017 Smart Grid Technology Plan Update[1] was presented to Company Management and Board for consideration of the project.

Customer Programs

Usage Alerts

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Usage Alerts program is designed to provide residential and small and medium business customers more transparency into their actual and projected electricity costs. Customers with a certified smart meter and email address on file with Duke Energy are automatically enrolled to receive a 'mid-cycle' email halfway through their billing cycle each month. This mid-cycle alert contains the customer's estimated electricity cost to date and projected cost for the month based on the customer's smart meter data and rate schedule. It also includes an estimate of the customer's electricity cost to date by major appliance and useful tips to help customers be more energy conscious and efficient. Customers have the option to further customize their alerts by enrolling in text message notifications and/or budget alerts, and updating their home profile information Budget Alerts notify customers when they reach 75% and 100% of the dollar amount they indicate in their alert preferences..

(ii) The status and timeframe for completion.

The Usage Alerts program became available to DEP customers with a smart meter and email address on file at Duke Energy in late July 2018. As of July 2018, the program has sent approximately 11,000 messages to 10,200 enrolled customers in DEP. 98% of customers who have provided feedback

[1] Pursuant to Commission request, DEP also completed a revised cost-benefit analysis and filed it on June 4, 2018 in Docket No. E-100, Sub 147.

on the program have indicated their satisfaction with the program. The complete roll-out of the program is aligned with the deployment of AMI meters across the jurisdiction.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The Company works with vendor partners to generate and send usage alerts to customers. Alerts are sent by default to the customer's email address on file with the Company and customers can update their alert contact information and/or channel preferences by accessing their preference page directly from the alert. The Company only transmits usage information as agreed to by the customer and the alerts display the street number and street name associated with the customer's account.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

This program incurred no capital expenditures.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

JD Power customer survey results indicate that customers are more satisfied with their utility when they receive more detail regarding their usage patterns and are notified when their usage is over a preset amount, so they are not surprised by their bill.

Pick Your Due Date

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Pick Your Due Date (PYDD) program allows residential and small and medium business customers to choose the bill due date that best meets their personal and financial needs. Customers can choose any date and can update their selected date one time each year. The program leverages smart meter capabilities such as remote meter reading to allow customers to select a due date outside of their pre-determined meter reading route schedule without creating meter reading inefficiencies.

(ii) The status and timeframe for completion.

The PYDD program will become available to DEP customers with a smart meter in early 2019. The complete roll-out of the program is associated with the full deployment of AMI meters.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

This section is not applicable.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

This program incurred no capital expenditures.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

JD Power customer survey results consistently indicate that customers are more satisfied when their utility offers the option to pick their own due date.

Outage Notification

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The Company started the Outage Initiatives (AMI) project in Q4 2017 to use smart meter data and technology to detect customer outages and restorations and identify meters mapped incorrectly in order to improve the accuracy and timeliness of customer communications sent during an outage. If an outage or restoration is detected, a message is automatically triggered and sent to the customer via email, text message, or automated outbound voice call to the phone number on file with the Company to inform them of the outage, provide a status update with estimated time of restoration, and confirm when power has been restored. This program is designed to improve customer satisfaction during an outage by enabling the Company to provide more reliable, accurate, and timely information to customers, minimizing the need for customers to self-report an outage. This program is designed to improve the customer experience during an outage by utilizing AMI technology to further improve upon existing outage alerts and communications. Using AMI technology, the Company can develop outage alarms to detect when an AMI meter is not responding and can alert the customer, providing them with more reliable and timely outage information. The majority of this software and technology is already in place and utilizes technology and data afforded by AMI meters.

(ii) The status and timeframe for completion.

The complete roll-out of the functionality and program is aligned with the deployment of AMI meters across the jurisdiction.

(iii) A description of any existing equipment to be rendered obsolete by the new technology, its anticipated book value at time of retirement, alternative uses of the existing equipment, and the expected salvage value of the existing equipment.

This section is not applicable.

(iv) A description of how the utility intends the technology to transfer information between it and the customer while maintaining the security of that information.

The Company transfers outage information to the customer via text, email, or voice channel, based on customer selected preference. The Company does not transfer any personally identifiable customer information. Due to the information not containing PII data, there is no need to encrypt or provide additional security in the messages sent. However, we do comply with all TCPA standards regarding spam, out-out, etc.

(v) A description of how third parties will implement or utilize any portion of the technology, including transfers of customer-specific information from the utility to third parties, and how customers will authorize that information for release by the utility to third parties.

This section is not applicable.

(vi) Approximate timing and amount of capital expenditures, including those already incurred.

The approximate capital expenditure approved for 2017 and 2018 for DEP in North Carolina was $76,384 and $674,982, respectively, of which $338,534 has been spent as of July 2018.

(vii) Analyses relied upon by the utility for installations, including an explanation of the methodology and inputs used to perform the analyses.

JD Power customer survey results consistently indicate that customers are more satisfied when their utility offers them outage status communications.

Completed Projects

The following information provides a summary of DEP projects which have closed since the 2016 Smart Grid Technology plan was submitted.

Yukon Feeder Automation Upgrade

Duke Energy uses Yukon Feeder Automation (YFA) software to manage and control its Self-Healing Networks across the enterprise. This software did not have functionality to control Self-Healing Networks in areas with high Distributed Energy Resource (DER) penetration. Distribution feeder circuits with a high penetration of DER were disabling their self-healing network functionality. With the increased growth of distribution connected DER, there was an increased need for YFA functionality that incorporates DER in its behavior. Therefore the Enterprise Project upgraded YFA software to the latest version with the DER functionality. In conjunction with this upgrade, new security functionality was also provided by the vendor and deployed as part of the scope of this effort across the enterprise. This project was completed in Q3 2017. The total costs at completion was $0.5 million for DEP

Self-Healing Networks

Self-healing technology provides an immediate benefit of increased system reliability using distribution line power devices such as switches, programmable reclosers, and circuit breakers, that are automated and capable of communicating via an intelligent control system. The control system, communications system, and power line devices all work together as a "team", serving to identify and isolate the portion of the system affected by a fault or other problem, thus minimizing the impact to customers. The self-healing network of equipment communicates to reconfigure the distribution network optimally to minimize the extent of the outage, and restore power to as many customers as possible.

Each self-healing team is generally comprised of triple blade switches, three-phase electronic reclosers with cellular modem, and communication controllers capable of transferring load between multiple circuits. The Self-Healing Network provides SCADA data to the DMS automatically and can support operation autonomously or under control.

Benefits include reliability improvements through fault isolation and reduced. Additional benefits include more efficient outage response, reduced outage assessment time, and reduction in emissions and safety hazards associated with fewer miles driven by field crews.

The DEP Self-Healing Network project was completed in the second quarter of 2018 at a total cost of $9.5M to add 90 new self-healing teams to the 20 that were already enabled before this project started.

Self-Healing Operations through 08/31/2018 (includes MED's)				
	SHT in Service	**Number of Operations**	**Customer Interruptions Avoided**	**Customer Minutes of Interruption Saved**
2014	20	2	3,417	106,651

2015	51	20	18,735	2,020,378
2016	78	68	66,413	14,092,657
2017	92	48	46,051	2,973,153
2018 YTD	110	89	107,479	9,011,481

Urban Underground Automation – Raleigh Pre-Scale Deployment

The Urban Underground Automation – Raleigh pilot project was Duke Energy's first Carolinas installation of an underground distributed intelligence loop distribution automation system. This type of system is installed in locations where load reliability can have a direct impact on safety, such as a downtown or dense multi-use location, or other high-profile places, like airports, stadiums, etc. Restoration times for this system allow isolation of events in seconds, with the system not dependent on communications to a centralized head-end solution. Instead, the system is able to make independent decisions and control actions within the distributed loop. Similar to Self-Healing Networks, this technology responds to a loss of power by utilizing real time data from intelligent sensors to isolate faults, reroute the power supply around the fault, and return power to as many customers as possible until the problem area is repaired. In most cases, this entire process occurs in seconds. In fact, most of the customers who would have lost power for at least 45 minutes with the current system will only experience a momentary interruption, or an outage of less than one minute.

This project provides visibility and automation to nine underground vaults in downtown Raleigh by integrating the distributed automation control system into the existing Distribution Supervisory Control and Data Acquisition (DSCADA) and Distribution Management System (DMS) through a fiber optic communication network. The project closed in Q3 2018 with a final project cost of $2.0M.

Mt. Sterling Microgrid

As stated in DEP's most recent Mt. Sterling Annual Progress Report (Docket No. E-2, Sub 1127), Duke Energy Progress completed the construction of an approximately 10-kilowatt (kW) direct current solar photovoltaic (PV) electric generation facility, an approximately 95-kilowatt hour (kWh) zinc-air battery energy storage system, and associated equipment for the Mt. Sterling Microgrid Project located on National Park Service ("NPS") property in the Great Smoky Mountains on Mount Sterling, Haywood County, North Carolina. The remote Microgrid serves a communication tower in the Great Smoky Mountain National Park. Construction of the Microgrid was complete in 2017 and official confirmation of the performance test took place in 2018. The total cost of the Microgrid was approximately $350,000. With the completion of the Mt. Sterling Microgrid, the existing 12.47 kV Waterville Village feeder is no longer the primary source of electricity for the communication tower. While the feeder equipment currently remains in-place, the feeder is de-energized, and decommissioning activities are expected to commence later this year.

4. Technologies Actively Under Consideration

Reference	Requirement
R8-60.1 (c) 4	*For all smart grid technologies actively under consideration for implementation within the next five years, the smart grid technology plan shall include a description of the technologies, including the goals and objectives of the technologies, as well as a descriptive summary of any completed analysis used by the utility in assessing the smart grid technology.*

DSDR/CVR Evaluation

Distribution System Demand Response (DSDR) is an operational mode of Volt Var Optimization (VVO) that supports peak shaving and emergency MW (demand) reduction. Duke Energy Progress (DEP) implemented DSDR in 2014. The DSDR mode of operation is implemented by the software within a centralized Distribution Management System (DMS). The DMS obtains telemetered data via 2-way communications from substation devices, distribution line voltage regulators, distribution line capacitor banks, medium voltage sensors, and low voltage sensors. The DMS software performs a power load flow analysis based on near real-time measurement inputs. Afterwards, it sends out commands to the voltage regulators and capacitor banks to optimize the voltage for DSDR. Currently, DSDR can provide peak shaving voltage reduction of approximately 3.6% across the distribution network in DEP. The DMS in DEP is capable of optimized modes (i.e.- DSDR) or non-optimized (i.e. – emergency) modes. The emergency modes are designed for a speedy, temporary response during bulk power emergencies with voltage reduction capability of up to 5.0%. Initially, the DEP DSDR targeted approximately 310 MW of peak demand reduction capability to defer construction of a new Combustion Turbine (CT) plant. The North Carolina Utility Commission classified DSDR as an Energy Efficiency program with rider recovery. The goal was exceeded and DEP achieved 322 MW of load reduction.

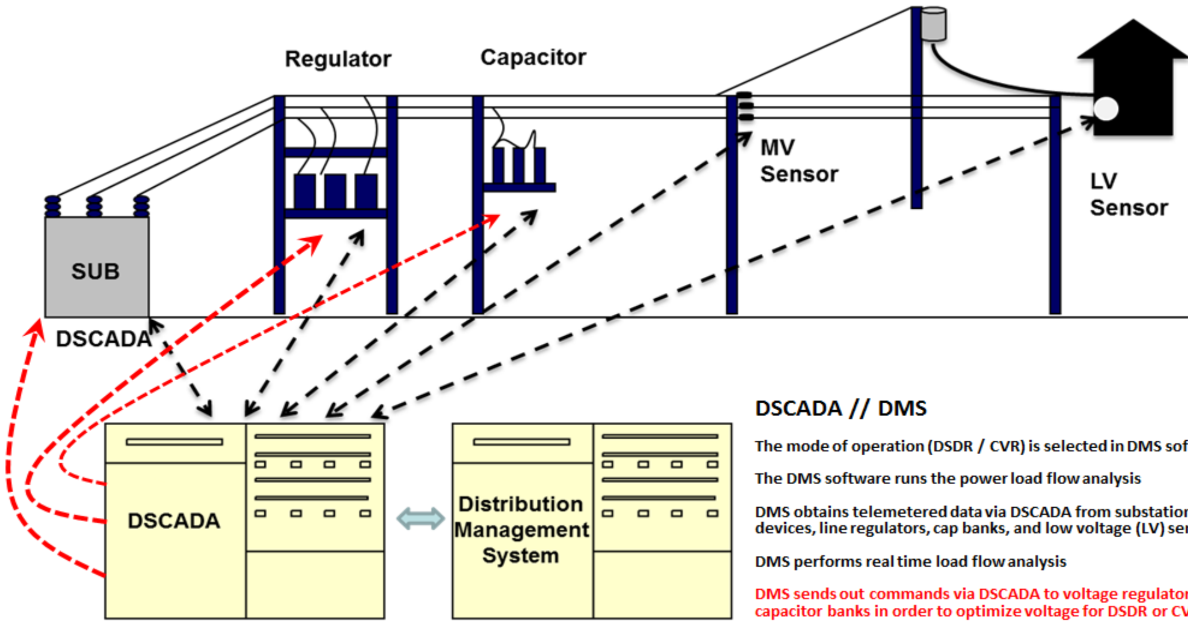
The initial implementation of DSDR not only included a Distribution Management System (DMS), but also a significant amount of circuit conditioning (such as installing voltage regulating devices and capacitors, balancing load on distribution circuits, and reconductoring some distribution lines to larger wire sizes). These forms of circuit conditioning help reduce line losses, which improve grid efficiency, reduce reactive power on the grid, and enable a higher voltage reduction to achieve maximum peak shaving. Additional devices, such as medium voltage sensors and low voltage sensors, were deployed to provide additional telemetry on the system. The substation and distribution line devices needed for DSDR were deployed in the optimal locations and equipped with 2-way communications ability.

The purpose of this evaluation is to conduct a cost/benefit analysis of moving DEP from the current DSDR (peak shaving) operational strategy to a Conservation Voltage Reduction (CVR) operational strategy. Conservation Voltage Reduction (CVR) is an operational mode of VVO that supports voltage reduction and energy conservation. The CVR functionality would target an estimated 2% voltage reduction for the majority of the hours of the year. This voltage reduction is estimated to result in an approximate 1.4% load reduction on average for enabled circuits. The substation, distribution, telecommunications, and IT infrastructure are already in place because DSDR already exists in DEP. As such, it is expected that few new devices will be installed. The current DEP DMS will transition to the enterprise DMS platform in the future. The software within the future enterprise DMS platform will have the ability to operate in various modes, including the current DSDR mode and CVR mode. This evaluation assumes the future version of the DMS platform will have already been deployed with the software capability to operate in DSDR or CVR mode, and that comprehensive testing will have already been performed on the required changes to the DMS system. Because the 2-way communications and control infrastructure are already in place in DEP, the settings on the substation and distribution devices can be programmed to enable these devices to properly operate when the DMS is in CVR mode or DSDR mode.

Changing the operational strategy in DEP from DSDR to CVR would affect the amount of maximum peak shaving capability. If the DMS is operating in CVR mode, transitioning to DSDR mode when load has already been reduced will not provide the peak shaving benefit realized today. The net result is that the amount of peak shaving would be reduced, and therefore will require relief from the current DSDR peak shaving obligation. This evaluation shows the incremental cost/benefits of transitioning to CVR operational mode. However, the lost benefits (including the initial deferral of peaking units,) due to the reduction of peak shaving capability have yet to be calculated. To make an informed decision, further analysis will be required to accurately quantify the impacts on DSDR. When the DMS upgrade is complete, Duke Energy will be able to conduct additional testing and a more thorough analysis of the peak shaving capability impact.

As part of the settlement agreement with EDF in the Piedmont merger docket E-2, Sub 1095 and E-7, Sub 1110, Duke completed a cost-benefit analysis for a broad deployment of Integrated Volt-Var Control in DEP territory, similar to deployment plan developed for Duke Energy Indiana. The results of the analysis are included with the 2018 SGTP Filing Exhibit 1 – DEP DSDR/CVR Cost Benefit Analysis.

DEP DSDR / CVR Illustrative Overview



DSCADA // DMS

The mode of operation (DSDR / CVR) is selected in DMS software

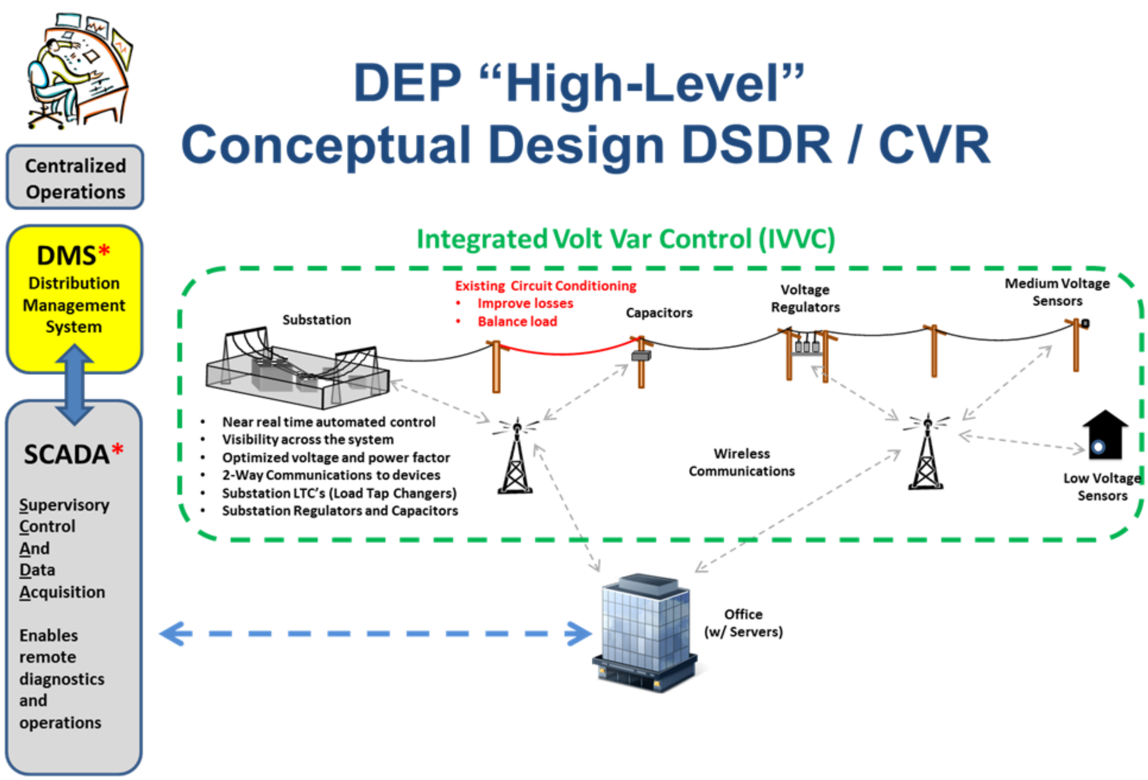
The DMS software runs the power load flow analysis

DMS obtains telemetered data via DSCADA from substation devices, line regulators, cap banks, and low voltage (LV) sensors

DMS performs real time load flow analysis

DMS sends out commands via DSCADA to voltage regulators and capacitor banks in order to optimize voltage for DSDR or CVR

DEP "High-Level" Conceptual Design DSDR / CVR



- DMS & SCADA already exists.
- The DMS Software will be enabled to operate in either DSDR or CVR mode.

Battery Storage and Microgrids

Battery Storage and Microgrid often include distributed generation and storage technologies as well as load-modification practices. While most battery storage and microgrid projects around the country have been driven by mandates or R&D efforts alone, Duke Energy has proactively evaluated these technologies and led multiple projects and plans that incorporate these non-wire alternatives. The primary applications for battery storage and migrogrid deployments can range from enhancing reliability to a community through local generators to increasing capacity to new customer loads or EV charging stations, for example, through local storage assets.

As discussed throughout this Plan, Microgrids typically integrate solar PV, battery storage, and other distributed energy technologies with the capability of isolating customer loads from the grid. The Mt. Sterling Microgrid, approved by the Commission and constructed in 2017, is currently serving a remote customer in a more reliable and cost-effective way than a traditional distribution feeder while also enhancing employee safety and productivity by mitigating O&M activity in a high-risk, labor-intensive environment. Similar opportunities to deploy renewable-based Microgrids will be considered when warranted by the cost of serving customers in a traditional manner from the distribution grid, customer demand, or other situations where reliability of service is critical.

As stated in DEP's most recent Western Carolinas Modernization Project (WCMP) Annual Progress Report (Docket No. E-2, Sub 1089), DEP has identified multiple opportunities to reduce peak load through load-modification measures and to site solar and battery storage capacity in the Western Region. The current deployment plan for WCMP includes a total solar capacity of 15 MW and total battery storage capacity of approximately 50 MW owned and operated by the Company. These include the Rock Hill and Hot Springs projects mentioned in Section 3 of this report. These deployments will serve as alternatives to traditional grid upgrades required to increase capacity and reduce outages.

The Company's latest IRP also outlines the many steps the Company is taking to further its commitment to non-wire alternatives like renewables and battery storage by working with utility customers on innovative and sustainable solutions while diversifying the Company's regulated generation, transmission, and distribution systems in a cost-effective manner.

5. Pilot Projects and Initiatives

Reference	Requirement
R8-60.1 (c) 5	*For each pilot project or initiative currently underway or planned within the next two years to evaluate smart grid technologies: (i) – (v)*

Physical & Cyber Security

Device Entry Alert System (DEAS)

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The objective of the Device Entry Alert System (DEAS) project is to install an entry door alarm head-end system and processes for tracking and monitoring physical access of distribution line device field Intelligent Electronic Devices (IED) devices and related infrastructure.

The current solution concept, still under review, will likely include:

- Addition of entry alarms to distribution line device panel doors that will activate when the door is opened (e.g. recloser)
- A system that integrates with the field device entry alarms, receives a notification when it is activated and pairs it with a virtual logging system
- A means of distinguishing between authorized and unauthorized entries, all notifications being logged and reported
- A means of autonomously "blacklisting" or limit communications with field cellular modem.
- Includes the development of the business processes related to the system monitoring and response

The concept, similar to the process utilized for Transmission substation entry, is focused on distributed equipment across the Duke Energy footprint

(ii) The status and timeframe for completion.

The in-service and completion date is still to be determined.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

$ in millions	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
DEAS	0.000	0.000	0 .000	0.416	0.099	0.000	0.000

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

The initiative is still in the planning stages.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

N/A

Distribution System Modernization, Automation and Intelligence

Sectionalizing Device with remote monitoring and control

(i) A description, including its objective and an explanation of how it will improve grid performance or provide improved or additional utility goods and services.

The Hydraulic Recloser Replacement Program is an enterprise wide effort to phase out oil-filled reclosers and replace them with solid dielectric sectionalizing devices with remote monitoring and control. This will provide a means by which to reduce Duke Energy's oil footprint and eliminate maintenance activities required for upkeep of the existing oil-filled fleet. This transition will be a phased approach to allow for the depletion of existing oil-filled inventory. Hydraulic reclosers have been separated into two categories by size: 140A and greater and 100A and less. Units 140A and greater are being replaced by the standard Duke Energy electronic line recloser. A replacement has not been finalized for units 100A and smaller which is the focus of this initiative.

(ii) The status and timeframe for completion.

An RFI was issued to multiple vendors in this space and alternative solutions are currently being evaluated. A solution is needed by 2020 when existing inventories of reclosers are depleted.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The project was not funded by government grants. A proof of concept is being developed to refine both the technical approach, cost and the business processes required.

	actual	Jan-Jul actual	Aug-Dec estimate	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Proof-of-Concept	0.000	0.000	0.000	TBD			
Total							

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

A proof of concept on the small electronic sectionalizing device with remote monitoring and control capability was conducted in which a cut-out mounted sectionalizing device was evaluated with a communications gateway. The proof of concept was unsuccessful and this solution was removed from consideration.

> *(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.*

The cut-out mounted sectionalizing device with remote monitoring and control capability proof of concept was not successful due to the fact that the communications gateway did not provide remote configuration management or remote firmware management of either the recloser units or the gateway itself. Also, the promised SCADA functionality (remote control and monitoring capability) did not work. The communications gateway would not connect to the Duke Energy DSCADA system.

Additional proofs of concept are planned for 2019 to evaluate the options presented through the previous RFI effort. The scope includes installation of a 3PH site and 1PH site to fully evaluate the capabilities of vendor offerings in the small electronic sectionalizing device with remote monitoring and control capability space.

Medium & Low Voltage Enhanced Volt/Var Capability Pre-scale

> *(i) A description, including its objective and an explanation of how it will improve grid performance or provide improved or additional utility goods and services.*

Duke Energy recognizes the need to have an agile and adaptive grid with the ability to be able integrate growing amounts of DER (Distributed Energy Resources), storage, promoting enhanced segmentation, two-way power flows, voltage support, and other capability enhancements over time. Continued DER integration into Duke Energy's distribution system will be important, also while continuing to develop capabilities that will allow Duke Energy's customers and stakeholders to realize the full benefits of an efficiently operated system, including voltage conservation/support capabilities (VC/S). The application of DER to distribution circuits can shift traditional VC/S methodologies and require lower latency response mechanisms within the VC/S space to respond to the rapidly changing conditions that DER can inject on an electric system. Duke Energy is evaluating more dynamic VAR support technologies such as stat vars and low voltage support devices that have the ability to quickly shift their characteristics with the variability of the local circuit and connected general network conditions. This effort will mainly focus on the use cases and maximized benefit application of medium voltage stat var devices. Stat vars are shunt voltage support devices that act much like a water tower acts to a bulk water distribution system. The stat var can act as a sink or source of vars for the connected electric grid and support the voltage dynamically, with low latency time. These devices may assist in reducing the operational stress that is placed on more traditional series mechanical voltage support devices, such as load tap changers (LTCs) and voltage regulators (VRs) by reducing their need to operate to respond to a shift in VOLT/VAR conditions, thus potentially extending their operational asset life and/or reducing the need for certain traditional technology in this space. Duke is evaluating several use cases for utilization and placement of the equipment. The pre-scale will attempt to place several units on active circuits to further develop and understand the use case capabilities of these devices and how they can benefit Duke Energy's customers and stakeholders in the operation of the electric grid.

(ii) The status and timeframe for completion.

The initial focus is the development of use cases, technical planning, and optimal placement of several initial devices in the pre-scale in 2019, while monitoring their performance into the following year. Depending on the success of the pre-scale's performance, this technology could potentially be applied in scaled manner to meet the specific use cases that this technology's capabilities could support.

(iii)The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The project will not be funded by government grants.

$ in millions	actual	Jan-Jul actual	Aug-Dec actual	estimate	estimate	estimate	estimate
Project	2017	2018	2018	2019	2020	2021	2022
Proof-of-Concept			0.000	1.105			

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

Not yet complete

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

Not yet complete

Customer Programs

Smart Meter Usage App

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

The company has been evaluating offering a potential enhancement to its residential My Home Energy Report Program (MyHER). This offering, previously referred to as the Smart Meter Usage App, has been branded internally as My Home Energy View (MYHEV). Similar to the existing MYHER program which has leveraged a customer's monthly billing data, the new offering will leverage the ability of the new AMI meters to provide interval usage data in hope of engaging, motivating and empowering customers to become more energy efficient. My Home Energy View is designed to give enhanced convenience and transparency to a customer regarding their electric energy usage patterns. This program installs a device in a customer's home that is capable of reading actual usage data from the smart meter in near real time and then communicates with an App on the customers phone via the customer's Wi-Fi. For this program, the extremely granular usage data is not provided back to the Company, it is only leveraged by the customer. By leveraging the app (provided to the customer) the customer can see real time usage and potentially the disaggregated view of their consumption (i.e. what applications in their home are consuming, broken down by the appliance – HVAC, refrigerator, base load, etc.).

Penetration testing has been completed for this technology and it met the required standards for compatibility with the AMI meters. Our next step is to pursue approval from IT Security.

The vendor states the expected life of the technology is 7-10 years, given the historical stability of the protocols they are supporting.

Finally, the Company needs to assess the program enhancement cost effectiveness to determine its feasibility to become a full-scale customer offering.

(ii) The status and timeframe for completion.

The Company is waiting for management approval to rollout the pilot. Pending approval, the pilot rollout would occur Q4 2019.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

The Company has incurred $1,598,231 to date investigating and evaluating this potential energy efficiency program enhancement.

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

A customer pilot has not yet been initiated so results are not available at this time.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The results of the planned pilot will help the company determine how to offer the program at scale, the expected participation rate, and the necessary regulatory filings.

Prepaid Advantage

(i) A description of the technologies, including the goals and objectives of each technology, options for ensuring interoperability of the technology with the legacy system, and the expected life of the technology.

Prepaid Advantage is a payment option that broadens the portfolio of Enhanced Customer Solutions and payment options. Prepaid is a purely voluntary option.

The Company is currently offering a pilot of Prepaid Advantage to a cap of 4,000 customers in DEC South Carolina. To inform future offerings and or expansion of the Pilot, Duke Energy is seeking to 1) validate that the Prepaid Advantage technology and data exchanges work as designed and meet the needs of customers; 2) measure and track participant data, behavior and satisfaction to evaluate the need and feasibility to expand the Program; and 3) Test the Program's overall ability to give customers the choice, control, and flexibility to pay, in real time, for electricity.

The Pilot is designed to give customers the control and flexibility to make payments to their account before using electricity. The amount one pays determines how much electricity one can use. The technology used for the Pilot will enable residential customers to see their electric consumption on a daily basis and monthly basis. Customers will be able to view usage and account balance information on a web portal (via desktop or Smartphone), and receive alerts through text messages, e-mail, and automated outbound calls, at their discretion. Customers will be able to use this information to recognize higher than usual electricity consumption on a daily basis, thereby better understanding what drives their costs. Furthermore, Prepaid provides residential customers with greater payment flexibility, allowing frequent cash payments which may help customers better manage their finances. Prepayment does not require a deposit fee, allowing customers to use funds to which they otherwise would not have access.

(ii) The status and timeframe for completion.

The Company is considering launching Prepaid Advantage for DEC North Carolina. More definite next steps will be confirmed in Q4, 2018.

(iii) The total cost incurred to date by the utility to conduct and investigate each pilot project or initiative, including whether and to what extent these projects are or will be funded by government grants.

To date, the Company has incurred approximately $550,000 to build, market and operate the South Carolina Pilot. Once the Program is launched for DEC and DEP North Carolina, the Company is unlikely to incur additional implementation costs. No costs have been incurred to date in DEP North Carolina.

(iv) A summary of the results of any pilot project or initiative that is completed if the final results of the pilot project or initiative have not yet been included in previous plans.

For the South Carolina Pilot, approximately 2,800 customers are enrolled today. Comprehensive results will be available following the completion of the Pilot. No results are available for North Carolina as the Program is not currently offered there.

(v) An explanation of how the results of the pilot project or initiative will be used by the utility if the explanation has not yet been included in previous plans.

The results of the planned pilot will help inform future offerings or expansion of the Pilot. The following data is being collected:

- Number of payments per month and average payment amount per customer;

- Number of nonpayment disconnects and reconnects;
- Customer energy usage patterns;
- Customer satisfaction; and
- Number of customers who choose to withdraw from the Pilot (other than move-outs) and the reason for withdrawal.

Emerging Technology Trends (ETO)

The Emerging Technology Office's (ETO) mission is to lead Duke Energy in the identification, evaluation, development, and application of emerging technologies - technologies that may not be ready for wide-scale deployment for another 3-10 years; to identify related business opportunities and risks; and to transfer technologies to the business units to optimize value in a dynamic technology, customer, and regulatory environment. Some technologies and trends may be evaluated and deemed non-viable or non-transferable. The ETO is continuing to evaluate emerging technologies such as battery storage, microgrids, and other grid-related technologies as listed below.

Microgrid Pilots

The US Department of Energy defines a microgrid as a group of interconnected loads and distributed energy resources (DER) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid is able to connect and disconnect from the grid to enable it to operate in both grid-connected or island-modes. Microgrids owned and operated by Duke Energy enhance resiliency, improve reliability, and deliver economic and environmental benefits to participating and non-participating customers. Non-participating customers will benefit from increased reliability to critical service facilities, emergency services, and/or other public purposes served by a microgrid. In addition, to the extent a microgrid is able to provide support to the grid, all customers benefit.

Integrating advanced protection and control technologies with DER in a microgrid supports the rapid operation of automated devices in response to an outage or power quality issue. Ultimately, this enhances the resiliency and reliability of customer electric supply. During a regional outage event, power generated by renewable technologies cannot be transmitted to the grid; the standard operating procedure is to isolate the assets. Microgrid technologies, however, allow the renewable assets and other DER within the microgrid to continue generating power for participating customers. Through multiple pilot projects and partnerships, Duke Energy is testing various microgrid control modes to evaluate and demonstrate how microgrids will automatically respond to and re-synch to the grid following outages. Current pilot projects include the McAlpine microgrid in South Charlotte and the Coalition of the Willing microgrid in Mount Holly.

McAlpine Microgrid

The McAlpine Microgrid was commissioned in late 2015 and continues to provide insight into the operational requirements of a microgrid on the utility system. Earlier in 2016, the microgrid successfully responded to a system disturbance and seamlessly transitioned the customer (Fire Station 24) from the grid, to the microgrid, and a return to the grid.

In the spring of 2016 a long-duration islanding test was developed and executed. The duration test was deemed a necessity to determine the performance of the microgrid components operating in a long-term island scenario. Testing also was required to fully understand the Auxiliary Power requirements needed to operate the network equipment, air conditioning, lighting etc. installed as part of the microgrid. The HVAC system in the Battery Energy Storage System required a change out during 2016 at a cost of approximately $15k.

The duration test proved that successful long-term support of Fire Station 24 can be provided by the battery energy storage system and solar. The microgrid controller performed very well, and managed the state-of-charge of the battery during periods of excess solar energy production by cycling the solar as needed. However, the performance of the battery was not as expected with the energy provided falling far short of expectations. Based on analysis of the data from the test, auxiliary power requirements consumed a large part of the energy needed to run the microgrid. The results of this test are already being used in other energy storage assessments, and are being used in industry forums and vendor meetings to influence the future direction of auxiliary and standby power requirements for energy storage systems.

<u>Mount Holly Microgrid</u>

Building off of the successes of The Coalition of the Willing work (Phase I and Phase II) and the growing industry acceptance of the Open Field Message Bus (OpenFMB™), the Mount Holly Microgrid is positioned as one of the most advanced microgrids in the country. Upgrades to the original microgrid were designed and are being continuously implemented to research new areas of interest. The heart of the microgrid is the 650kW/326kWH Saft Li-ion battery installed in 2017. The battery runs in voltage source mode continuously which provides the microgrid, when islanded off of the Duke Energy grid, the voltage and frequency support it needs. The brains of the Mount Holly Microgrid is a Schweitzer Engineering Laboratory Real-Time Automation Controller which is installed in the new 4-way islanding switch from G&W Electric. This combination allows for seamless islanding and reconnection to Duke Energy's grid. The standard operating mode for the microgrid is islanded. The integration of 150kW of solar panels and the Saft battery allow the microgrids load to be disconnected from the grid for a majority of the day. The only times that the Mount Holly Microgrid connects back into the Duke Energy grid is to charge the battery. This generally happens late at night or if clouds prevent the solar array from producing power to charge the battery during the day. The upgrades to the Mount Holly Microgrid cost $1.4M which includes material, labor and integration costs.

This work has continued to advance Duke Energy's knowledge base around microgrids and the need for more distributed intelligence and interoperability between devices in the grid. The ETO is continuing to transfer lessons learned around our work to other Duke Energy business units to provide valuable outcomes for our customers. Further work is ongoing at Mount Holly to expand the use of OpenFMB to easily integrate DER devices into the microgrid. In 2018 and early 2019, a new 500kW natural gas generator will be installed to provide additional functionality to the Mount Holly Microgrid. The use case being researched is to better understand how a customer with existing generation may implement a microgrid. This generator represents the first rotating mass generation device on the Mount Holly Microgrid. The project cost to install the generator on the microgrid is $650k. This price includes the generator, the gas line extension to the site, and all of the interconnection work involved in getting it connect to the existing microgrid.

The Emerging Technology Office is analyzing all the results from the installation and operation of the microgrid to evaluate technical, operational, and financial benefits for customers and the utility. The goal is to potentially offer new products and or services to customers to assist them in meeting their evolving energy needs.

<u>Rankin Circuit</u>

As an important next step and logical extension to the Coalition of the Willing phase II project, a field test of the same interoperability concept will be conducted at the Rankin circuit on which the Mount Holly microgrid resides. The Rankin circuit test, which is on track to become Duke Energy's second reference implementation of the OpenFMB™ standard, will include the active coordination of the DER devices within the Mount Holly microgrid, a substation battery system, distribution automation devices, and a 1.2MW of solar at the end of the circuit. Similar to the OpenFMB™ microgrid facility at Mount Holly, the Rankin circuit will leverage the industry standards stakeholder community at the Smart Grid Interoperability Panel (SGIP) for the definition and consensus on the operational use-case – DER circuit segment management – to be employed at this test site with the intent to demonstrate how distributed intelligence can help enable multiple functions that lead to stacked benefits. Prior to its implementation on the Rankin circuit, a variety of scenarios of this foundational use-case will be developed and validated inside the Mount Holly lab using real-time simulation creating a digital twin of the circuit. ETO personnel and UNCC EPIC students are designing this hardware in the loop (HIL) simulation. Started in 2017 and continuing throughout 2018, there will be approximately $750k spent on this work. Furthermore, the Rankin circuit model will become the baseline validation instrument for new emerging use-cases to be developed and simulated before future operational pilot testing on Duke Energy power system and telecommunications infrastructure in 2019 and beyond.

Energy Storage Pilots

Distributed energy storage continues to gain momentum as a viable solution as the price of batteries continues to drop and utility operators experience more installations on the system. The Company is continuing to evaluate additional storage opportunities with various chemistries across multiple use cases. Batteries offer flexibility by being able to perform a multitude of functions. Distributed batteries have the ability to offer capacity, spinning reserves, solar and wind smoothing, loss reduction, outage ride-through and other system benefits. In addition to the projects discussed in previous filings, Duke Energy continues to evaluate and demonstrate these many capabilities at different points on the grid.

For 2018 a directional shift was made to evaluate "non-lithium" technologies. This shift was made due to several factors:

1) Lithium Ion battery technology is commercially available in the marketplace and its performance is well understood.
2) Multiple vendors have approached Duke Energy ETO with super capacitor and aqueous hybrid type energy storage technologies. The large number of these vendors shows promise that some of these technologies will be successful.

Distributed Energy Storage Projects in the Carolinas

Several projects are in the planning and development stages at present, with field installations expected to be completed in 2018 and 2019, as listed below:

Rankin Hybrid Energy Storage

Located at the Rankin substation in North Carolina, the project originally tested a 402-kilowatt (kW) battery linked with a commercial solar installation located 3 miles away. The original solution testing was completed in 2015, and a new hybrid distributed storage solution was installed in the first quarter of 2016. This novel solution pairs two storage technologies from different vendors - a high energy battery solution from one vendor, with a high-power capacitor solution from the other vendor. Total system rating is approximately 370 kW and 600 kWh. The objective of this project was to understand the potential of hybrid battery solutions to improve the performance, life-cycle, and cost of energy storage solutions. This is also the first time that multiple storage solutions have been installed by Duke Energy with a common DC bus and shared inverter. This project uncovered a multitude of issues and nuances in the control and dispatch of energy storage assets connected on a DC bus. The main issues that arose during this project involved the requirements for fast and deterministic controls between the DC/DC converter and inverter. Because the original vendor did not properly design the control system these communications and the overall control scheme was determined to be unusable long term. This project brought to light the real-world issues the industry still faces in real time controls and was a great learning point for how we will specify future systems.

Emerging Technologies still believes there is high potential for ultra-capacitors to provide better high power, short duration impact for solar intermittency and voltage sag mitigation. It was therefore determined that a retrofit of the existing hybrid energy storage system would be required to fully understand the potential of the ultracapacitor technology. Between 2018-2019 Emerging Technologies will be retrofitting the existing site with a new Ultracapacitor system built specifically for utility applications. This system will also utilize a more robust inverter architecture, built for system resiliency, and remove the interconnection of another battery on the DC bus.

The retrofit project will leverage the infrastructure of the previous Rankin storage device, as well as in-kind contributions from multiple vendors. Duke Energy will invest approximately $500k, approximately half of the total installed cost of the retrofit system.

Marshall Energy Storage

The currently installed 1.2 MW solar and 250 kW Energy Storage System at this site are being utilized to develop algorithms to manage distribution-tied DER integration. The work is being developed and tested in partnership with UNC-Charlotte's EPIC Center. Self-learning forecasting routines will incorporate weather, circuit and usage data to best determine how to operate DER at different times of the day and seasons to offset voltage rises on the circuit and fluctuations due to solar intermittency and to reduce voltage regulator operations.

Duke Energy has invested $115k in 2015 and $137k in 2016 in the development of the algorithm software and readying the software for installation at the Rankin circuit in Mt. Holly to test the "self-learning" capabilities that may be required in the future.

The Marshall energy storage site is located on the coal ash fill at the Marshall generation plant site. Due to the new requirements related to working at a coal-ash location, additional testing at the Marshall energy storage site will be reduced in the future. Consideration will be given to removal of this test bed, but a final decision has not been made.

ETO is currently evaluating repurposing of the Marshall energy storage site to allow testing of the Regulated Business Energy Storage Control system to be deployed on the 2019 Regulated Energy Storage projects. ETO has spent $6K to have the S&C Inverter serviced at the site. A request has been made to Kokam to provide a quotation to have the Kokam battery serviced. We are awaiting the quotation for that service. If testing moves forward total 2018 spend will be $20K-$30K.

McAlpine Solar DC Coupled Energy Storage

Located at the McAlpine Creek Substation is a 50 kW solar field that is part of the regulated solar generation fleet. Duke Energy has entered into contract with EOS Energy Storage to test their Zynth energy storage technology in a DC coupled arrangement with the solar. DC coupled energy storage and solar proposes to provide efficiencies to capture clipped energy and shoulder energy that would be wasted without the energy storage ability to capture it. This energy would be discharged into the grid to help offset the duck curve in the evening.

The EOS Energy Storage Zynth technology offers several advantages over lithium ion based energy storage:

1) Does not require active air conditioning
2) Is non-hazardous and chemically safe. Can be shipped without hazardous handling.
3) Will not burn
4) Can be charged and discharged from 100% to 0%. All energy in battery can be used.

The project is being designed in Q2-Q3 2018 and construction will begin in Q4 2018. The EOS battery will be delivered in Q1 2019 with full operation expected in Q2 2019. An 18-month test period has been designated with complete reports for intended use cases as the deliverable. Total expenditure is $275K with a 2018 spend of $100K.

Kilowatt Labs Super Capacitor Evaluation

Kilowatt Labs is a manufacturer of super capacitor based energy storage systems for the small and medium commercial and industrial marketplace. Kilowatt Labs claims that their Sirius Energy Server technology which manages the charge of the super capacitors will allow energy capacity of the super capacitors to be roughly 4 times that of rival systems. Combined with the short duration charge and discharge times and the very high number of charge and discharge cycles make the technology attractive for high cycle applications. ETO will take delivery of a test system at the Mount Holly test lab in Q3 2018 with an operational date of Q4 2018. Total expenditure for the project is estimated at $30K.

Tesla PowerPack 2 Energy Storage System

In 2016 Emerging Technologies decommissioned an ATL battery that was initially part of the Mt Holly microgrid due to constant issues with thermal management, limiting the overall energy the battery system could provide. A Tesla PowerPack 2 energy storage system was selected as a replacement to be installed in 2018. The system will interconnect to the existing microgrid, utilizing infrastructure installed for the original ATL battery. This energy storage system will be used in current source to supply power to the islanded building when not connected to the grid. This system will also be commissioned to operate as a voltage source for the microgrid in the event of failure of the existing Saft energy storage system. This high availability design could be a potential customer offering in future microgrid projects. In grid connected mode the Tesla battery will be utilized to balance real time power flow to ensure that no power is exported out of the microgrid.

The total project cost for this system is approximately $500k, with Tesla giving Duke Energy special pricing consideration due to the research nature of this project. Duke Energy will be able to leverage existing assets to further reduce the costs of installation.

Residential Energy Storage (RES)

Commercially available battery solutions are emerging for residential applications. In principle, multiple customer-sited battery solutions could be aggregated to provide benefits to the electric grid, as well as short duration back-up power to customers. Emerging Technologies installed 3 separate residential energy storage installations at the Mt Holly Microgrid Innovation Center to test capabilities and get a better understanding of the total install cost and maintenance requirements.

Approximately $50k was invested by Duke Energy to investigate the three-separate residential energy storage installations. Installation costs ended up being approximately half of the total install costs for these systems, much larger than anticipated. Issues arose when using an inverter manufacturer that was different than the battery manufacturer in one of the installations, leading Emerging Technologies to recommend that any future program only contain one point of contact for behind-the-meter energy storage solutions. Overall the installations were technically successful, but it became clear that residential energy storage vendors have the mindset that these systems will be purchased and operated by home owners and not utilities. Due to this there are limited value propositions for utility applications with current iterations of these systems. The main value proposition to customers in Duke Energy's service territory was determined to just be backup power, while the utility can take advantage of demand response applications.

Pika Energy Storage

The Pika Energy Island is being installed for testing and evaluation at the Mount Holly test lab in 2018. The Pika Energy Island is a full microgrid system with energy storage, solar and smart inverter technology combined. The technology is unique in that it provides the ability to balance the energy storage, solar energy output and customer so that the grid supply is net zero. Neither importing nor exporting any energy from/to the grid when commanded to. This functionality may be of interest to Duke Energy in the future as more residential energy storage and solar is deployed. Expenditure for the testing in 2018 is $30K.

Zero Net Energy Homes

Advances in residential home construction have improved home performance substantially over the last decade. Additionally in the past few years, more and more new homes are being equipped with solar and smart home features as builders compete on connectivity, customer convenience and operational cost. An end result of the combination of these technologies can lead to Zero Net Energy Homes – homes that are very energy efficient and produce enough onsite generation to completely offset their load on an annual basis. The building-in of energy efficiency and smart home features, also provides greater capability for these homes to contribute to balancing and operation of a more flexible and changing grid but only when operated with utility's needs in mind. To this end Duke Energy has partnered with Meritage homes and EPRI to build 6 homes across Florida and North Carolina to understand how customer energy efficiency, home automation and distributed generation can be used for both the customer and utilities benefit. Technologies being investigated in these homes are: solar, high thermal mass insulation, heat pump water heaters, energy storage and conditioned attic space. This project is expected to provide the public and utilities a much better insight into how advanced construction techniques and new connected customer technologies could enable grid balancing.

To complete this project Duke Energy invested approximately $125,000 with a significant portion of the research funding coming from EPRI. The homes will be completed in 2018 and then post occupancy analysis will take place to determine best optimization of the different technologies to ensure utility system benefit and occupant comfort and convenience.

AMSC Mini-D-VAR® M-Series Device

The recent increase in the installation of distributed energy resources on the distribution system, associated with intermittency has resulted in large voltage variations on distribution feeders, which cannot be effectively mitigated by the use of voltage regulators. Depending on the size of the distributed generation (DG) source, its location on the feeder, impedance to the strong source on the sub-transmission/transmission side, voltage fluctuations could propagate throughout the whole feeder and cause reduced power quality across all customers. In order to mitigate this occurrence, there are a couple of available solutions: energy storage solutions, low voltage power electronics devices installed on the transformer secondary's, and now the medium voltage dynamic regulator.

This project aims to investigate a new technology manufactured by American Superconductor Corporation which makes a device called Mini-D-VAR® M-Series, 15kV Dynamic VAR Compensator. This device can potentially be used for voltage stability/VAR support and renewable energy applications such as voltage compliance, grid reliability, efficiency, energy savings and grid integration of distributed PV.

The project was engineered, procured and installed in 2017 at an approximate cost of $225k. During 2018, the pilot will focus on the several potential impacts:

1) Grid Optimization
    a. CVR/Peak demand reduction
    b. Improvement of volt/VAR optimization benefits
    c. Reduction of line loss and power factor improvement
2) Grid Integration
    a. Improvement of grid integration with PV solar systems
    b. Reduction of the impact of load dynamics
    c. Reduction of the operation of primary control assets
3) Grid Voltage Support and Visibility
    a. Mitigation of low/high voltage pockets
    b. Improvement of power quality – voltage sags/swells

The Lagrange Substation in the Duke Energy Progress territory has three feeders, each of which has distributed generation in form of PV solar arrays with a capacity of 5MW or greater. The DG sites are located at different distances along the distribution feeders from the substation. In order to mitigate the voltage variation and regulate the reactive power flow, this power electronics solution is being tested. These devices provide +/-1MVAR of reactive power (both inductive and capacitive) and is installed at one of the sites on a Lagrange Substation distribution feeder. This device will be used to assess its capability to reduce the voltage variation at this site and control the power flow.

6. Projects No Longer Being Considered

Reference	Requirement

R8-60.1 (c) 6	*A description of each project or initiative described in a previous plan that is no longer under consideration by the utility, and the basis for the decision to end consideration of each project or initiative.*

At this time, the Company does not have any project or initiatives previously reported that are now no longer being considered.

7. Advanced Metering Infrastructure (AMI) Summary

Reference	Requirement
R8-60.1 (c) 7	*For automated metering infrastructure (AMI), in addition to the information required in subsections (3) or (4) of this section, as appropriate, the utility shall also provide: (i) – (iv)*

(i) A table indicating the extent to which AMI meters have been installed in the utility's service territory and specifically in North Carolina, the North Carolina jurisdictional customer classes and/or tariffs of customers with AMI, and the predicted lifespans of these installations. This table should indicate the number of AMI meters that has been installed both cumulatively and since the filing of the last smart grid technology plan. *(ii) The number of meters in North Carolina that use traditional metering technology and/or automated meter reading (AMR) technology, and the predicted lifespans for these installations.*

Meters installed in DEP North Carolina as of August 2018

Customer Class	AMI Meters	AMR Meters	Walk-By & Other Meters
NC Residential	144,227	1,061,084	8,214
NC Commercial	48,893	139,943	14,132
NC Industrial	1,435	549	1,770
NC Company Use & Other	108	143	240
Totals	**194,663**	**1,201,719**	**24,356**

DEP has installed approximately 137,844 smart meters since the information provided in the 2017 Smart Grid Technology Plan Update. The AMR meters are being recovered over a period of 10 years and the smart meters will be depreciated over a period of 17 years pursuant to the terms set forth in the Company's last rate case proceeding Order entered February 23, 2018 in Docket No. E-2 Sub 1142.

(iii) Any adjustment made by the utility to its capital accounting due to AMI, including the dollar amount of write-downs of its meter inventories.

In the Commission Order approval in Docket No. E-2, Sub 1142 dated February 23, 2018, for the Company's request to include the amount for retired meters in a regulatory asset the Commission approved the Stipulation filed November 22, 2107, wherein the Stipulating Parties have agreed that a 10-year remaining life will be used for the meters that are being retired pursuant to the Company's AMI program; and a 17-year life will be used for new AMI meters. In its Order, the Commission further authorized DEP to defer to a regulatory asset account, the cost of the existing AMR meters being replaced by AMI meters.

(iv) A discussion of what AMI services or functions are currently being utilized, as well as any plans for implementing other AMI services or functions within the next two years.

DEP is currently utilizing the remote meter reading functionality of the AMI meters, replacing walk-by and drive-by meter reading. Along with the usage reading, the AMI meters also provide enhanced detection of meter tampering. DEP is also utilizing the remote order fulfillment capabilities of the meters, allowing for remote off-cycle reads or re-reads, remote reconnections and disconnections, and read-in/read-out orders to stop or start service.

For customers with an AMI meter, DEP also provides the ability to access day prior electric usage information via the internet-based Customer Portal. The Portal displays usage information up to and including prior day usage. Customers can view daily and average energy usage by billing cycle or month. Customers can also view average energy usage by day-of-week, and hourly energy usage by day or week, including average temperature data. Usage data is available for the previous 13 months, or as of the AMI meter certification date. Time-of-Use and Demand customers are able to view the information above, and can also see the date and hour when the peak usage or peak demand occurred, for the current or selected billing cycle. Customers also have the ability to download their hourly usage data from the Customer Portal in a .CSV format.

Usage Alerts is a customer program enabled by the AMI meters that is currently being deployed. Other programs planned for implementation within the next five years include Pick Your Due Date and Outage Notifications. All of these programs are discussed in detail in Section 3 above. Pilot programs planned within the next two years include the Smart Meter Usage App and Prepaid Advantage and are outlined in Section 5 above.

Pursuant to the terms of the North Carolina Utilities Commission's March 7, 2018 *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data* (March 7, 2018 SGTP Order) in Docket No. E-100, Sub 147, Duke Energy has convened meetings with the NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data. See SGTP Exhibit 2 for additional information related to these meetings.

NOTE:
The value of lost benefits due to the reduction in peak shaving capability are not included in this Cost/Benefit analysis, as further testing will be required.

Conservation Voltage Reduction (CVR) Operational Mode
Incremental Cost Details

Incremental Project Capital								
COSTS ($1,000)	NPV	Year 1	Year 2	Year 3	Year 4	Total Deployment	Years 5-26	Total 26 Year
TRANSMISSION	366	98	100	102	104	404	0	404
TELECOM	0	0	0	0	0	0	0	0
IT	3,794	1,008	1,033	1,059	1,085	4,185	0	4,185
DISTRIBUTION	3,285	879	896	914	933	3,622	0	3,622
PM / AFUDC	935	248	258	260	265	1,031	0	1,031
Total Incremental Capital	8,380	$2,233	$2,287	$2,335	$2,387	$9,242	$0	$9,242
Total O&M								
TRANSMISSION	4	1	1	1	1	4	0	4
TELECOM	0	0	0	0	0	0	0	0
IT	38	10	10	11	11	42	0	42
DISTRIBUTION	33	9	9	9	9	36	0	36
PM / AFUDC	0	0	0	0	0	0	0	0
Total Incremental O&M	74	$20	$20	$21	$21	$82	$0	$82
Total Incremental Cost	8,454	$2,253	$2,307	$2,356	$2,408	$9,324	$0	$9,324

Conservation Voltage Reduction (CVR) Operational Mode
Incremental Benefit Details
(with CO2 Benefit)

BENEFITS ($1,000) : (With CO2 Benefit)									
BENEFITS ($1,000)	**NPV**	**Year 1**	**Year 2**	**Year 3**	**Year 4**		**Total Deployment**	**Years 5-26**	**Total 26 Year**
Operational Benefits									
Improved VAR Mgt	**0**	0	0	0	0		**0**	**0**	**0**
Fixed O&M	**0**	0	0	0	0		**0**	**0**	**0**
Variable O&M	**(10,756)**	0	0	0	(307)		**(307)**	**(563,546)**	**(563,853)**
Reagent Cost	**(64)**	0	0	0	(3)		**(3)**	**(164)**	**(167)**
Start Cost	**(5,799)**	0	0	0	19		**19**	**(14,944)**	**(14,925)**
SUBTOTAL:	**(16,620)**								
Customer Benefits									
Fuel	**(192,539)**	0	0	0	(2,980)		**(2,980)**	**(521,364)**	**(524,344)**
SUBTOTAL:	**(192,539)**								
Operational Benefits and Customer Benefits									
SUBTOTAL:	**(209,159)**								
Environmental Benefits									
SO2	**(3)**	0	0	0	(0)		**(0)**	**(6)**	**(6)**
Nox	**(178)**	0	0	0	(7)		**(7)**	**(405)**	**(411)**
CO2	**(57,011)**	0	0	0	0		**0**	**(183,928)**	**(183,928)**
SUBTOTAL:	**(57,192)**								
TOTAL (All Benefits)	**(266,351)**	**0**	**0**	**0**	**(3,277)**	**0**	**(3,277)**	**(1,284,357)**	**(1,287,634)**

TOTAL COSTS									
COSTS ($1,000)	**NPV**	**Year 1**	**Year 2**	**Year 3**	**Year 4**		**Total Deployment**	**Years 6-26**	**Total 26 Year**
TOTAL CAPITAL	$8,380	$2,233	$2,287	$2,335	$2,387		**$9,242**	**$0**	**$9,242**
TOTAL O&M	$74	$20	$20	$21	$21		**$82**	**$0**	**$82**
TOTAL:	**$8,454**	**$2,253**	**$2,307**	**$2,356**	**$2,408**		**$9,242**	**$0**	**$9,324**

Key Financials:

Key Financials	
Investment Period:	**26 Years**
Net Present Value (NPV):	**$257,897 M**
Benefit / Cost Ratio (26 Year NPV):	**31.5**

SGTP Exhibit 2 – Commission's Rules on Third Party Access to Customer Usage Data

The North Carolina Utilities Commission's March 7, 2018 *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data* (March 7, 2018 SGTP Order) in Docket No. E-100, Sub 147, directed Duke Energy to convene meetings with the NCSEA, the Public Staff, and other interested parties to discuss guidelines for access to customer usage data; file a report with the Commission providing the details of the discussions and the parties' plans for further discussions; and reflect the results of these stakeholder discussions in its 2018 SGTP reports.

Pursuant to the March 7, 2018 SGTP Order, Duke Energy held a discussion with the parties in Raleigh, NC on May 23, 2018. In attendance were representatives from Duke Energy, Dominion Energy, Public Staff, NCSEA, Plot Watt, City of Durham/Durham County, SELC, and EDF. A report of the May 23 meeting was filed on June 21, 2018 in Docket No. E-100, Sub 147. Based on the discussion at the May 23 meeting, Duke Energy and the parties decided to have a series of breakout meetings to allow for the in-depth discussion of specific topics with the involvement of needed experts. Those breakout topics were for Data Definition (granularity, data fields, validation, etc.), Cost (implementation estimates and cost recovery approach), Compliance and Authorization (3rd party registration and certification process), and Customer Experience. Breakout discussions were completed and the parties reconvened as a whole on July 10, 2018. The following is a summary of the conference:

Customer Usage Data Access Conference *Summary & Next Steps – July 10, 2018*

A second conference between Duke Energy and interested third parties was held in Raleigh, NC on July 10, 2018 at 9am EDT to further review and discuss certain elements of Green Button's data sharing policy, such as data definition, cost, compliance and authorization, customer experience.

Attendees: Duke Energy, Dominion, NC Public Staff, NCSEA, Plot Watt, City of Durham/Durham County, SELC, Environmental Defense Fund, Mission Data, Energy NC

Discussion Topics:

- **Data definition**
    - There are four categories (customer data, billing data, usage data, and systems data) of information that capture the range of customer information that can be / should be portable to customers.
        - Any information that is specific to the customer, or generated by the activity of the customer – such as energy usage and resulting bills is referred to as "standard customer data."
    - Customer data (name, address, phone number, other basic info, etc.)
        - Ties to account (helps with multi-premise)
        - Customer needs to provide consent initially
        - Hardware constriction from AMI meter, may be bound by this
    - Usage file (provided more frequently)

        - Amount of historical – four years is seen as best practice
        - System data points for demand response & wholesale market customers
        - Two pieces of data
            - PII (personal identifiable information) Customer Data
            - Non PII Usage data
        - Ties to meter
        - Kwh based on interval
        - We already have access to this, just a matter of putting it into Green Button framework
        - Today, customers can go to portal and download usage data and always download in hour interval, meter interval differs by metering instructions
        - Ideal to have 15 min interval esp. for commercial customers
    - There's a unique identifier which can link these files
    - Taking the "Best Available" data can be an important approach
    - Quality of reading indicator:
        - Raw
        - Validated
    - 24 hour turnaround is acceptable and complies with standard
    - Possible indicator that it failed validations, versus providing a zero read
    - Size of file can be handled by utility – and compressed if needed
    - Meter changes:
        - What is the level of authentication?
            - Meter or
            - Customer or
            - Premise or
            - Account
    - Utilities and Green Button now looking at also providing PDF version of Bill to 3rd party (versus customer providing login/password to website)
    - There was a request to provide a database (comma delimited, etc.) file of billing information – machine readable format

- **Cost – to identify cost / benefit elements. Discussion included:**
    - System Development Costs – John Finnigan named two vendors that were used by other companies, including Schneider Electric and O'Power. Duke could ask for bids to offer this as a monthly software lease or Duke could build our own.
    - Ongoing transmittal of the Data to the 3rd parties
    - Creation and maintenance of a testing environment for 3rd parties
    - Vendor Authorization and Registration Process
    - Stakeholder/Customer Engagement
    - Customer Signup
    - IT Security / Cyber Audits
    - AMI Obsolescence Risk – Doubtful this would be monetized in a CBA but there could be a future where the 3rd party vendors determine that a different kind of data not currently captured by AMI would prove beneficial. This would likely have impacts on customer rates.

- Data Breach Risk – This is primarily dealt with in the contractual agreements between Duke and the Customer and Duke and the 3rd Party. In both cases, Liability Waivers would be absolutely necessary.

- **Authorization**
  - This element encompasses providing standardized language for the customer to support their informed consent.
  - Third parties required to provide utilities certain criteria (see below)
    - Contact info, including federal tax ID number
    - Certificate of good standing from the state
    - Agree to reasonable terms of utility data access
    - Complete technical interoperability test with a utility's GBD platform
  - In other states – the utility checks that criteria are met, but no arbitrator role
    - Often the commission investigates reports of bad actors
    - Commission could declare them a bad actor and they would be black listed from receiving usage information
  - Performance standard (bandwidth and security)
  - Some states put it on the customer to decide and require the customer to realize the risk
  - Data breaches should be disclosed – California required disclosure of any breaches of a third party or any transfer-related issues
  - Registration (customer) is different than Authorization/Certification (3rd party)
  - For utility list of third party, the utility will be provided a logo and link to the services the third party provides
  - Purpose of consent – if the third parties purpose changes, it should require additional/regained consent
  - Requirement for ability of customer to grant access and registration to send data to third party
    - Look at continuation of how to reauthorize (How often to require? What is the customer experience – needs to be defined)
  - Need to understand role of commission regarding revocation – may likely require additional rulemaking

- **Customer experience**
  - Review of five discrete authorization processes for customers. These processes should make use of a customer's online utility account, if one is already created, but a utility account should not be required. These include:
    - 1. Customer has an online utility account
    - 2. Authorization without a utility account
    - 3. Customer authorization via Third Party designs
    - 4. Warrant process
    - 5. A paper-based form
  - Consider customers with many facilities – review use cases here (e.g., property owner vs lessor, energy manager for school district, apartment complex, etc.)
  - Test environment is critical (we would need to test the different authorization processes to ensure they function properly prior to go-live)

Next Steps:

- **Data definition**
  - Review current files / embedded fields (e.g., tariff profile, usage summary, interval blocks) to understand if format will work / be meaningful for customers
  - Review schema, choose fields of interest; leverage best practice / expectations from this group

- **Cost – determine if cost can be recovered through base rates**
  - Review business case and customer adoption rates for Excel Energy model in Colorado, Ontario Commission
  - Review New York Utility Commission re: utilities' justification for selecting Green Button
  - Conduct cost / benefit analysis for Duke Energy

- **Authorization –** Who is responsible for managing certificates of good standing?
  - (Document retention will likely be a hurdle (e.g., which function at utility does this, manual / paper process)