Curriculum Vitae – Dennis Stephens EE

Wired Group, PO Box 620756, Littleton, CO 80162 dstephens@wiredgroup.net 303-997-0317

Profile

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

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

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

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

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

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

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

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

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

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

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

2016 – Senior Technical Consultant, Wired Group.

Noteworthy Projects

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

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

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

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

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

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

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

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

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

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

High Pressure Gas Pipe Replacement Program, 1988. Initiated and managed the renewal and replacement of 26 miles of high pressure gas pipe, over a 5 year period, reducing the likelihood of seam failures as outlined in an "Alert Notice" issued by the Department of Transportation's Office of Pipeline Safety. Project roles included community

engagement, government and regulator relations (PUC, DOT, EPA), and contractor management. Project completed 1 year ahead of schedule and 14% under budget.

Regulatory Appearances

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

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

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

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

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

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

Notable Publications and Presentations

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

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

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

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

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

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

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

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

Education

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

Awards

National Edison Award for Utility Innovations, 2006.

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

Docket No. E-7, Sub 1214

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

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

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

Docket No. E-7, Sub 1214

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

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

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

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

Docket No. E-7, Sub 1214

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

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

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

Docket No. E-7, Sub 1214

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

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

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

Docket No. E-7, Sub 1214

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

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

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

DEC NCJC DR 8-34
g. Number of Outag

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

Docket No. E-7, Sub 1214

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

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

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

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

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

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

Docket No. E-7, Sub 1214

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

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

2-4. Please refer to DEC's response to NCSEA DR 2-19, which indicates that the physical security of 11-13 substations will be upgraded annually at a cost of $4.2 million each. Provide a rough split of this $4.2 million budget for each the substation components listed in DEC's response to NCSEA DR 2-19:
a. High-security perimeter fencing;
b. Intrusion detection/cameras/lighting;
c. Pre-fab security equipment enclosure building;
d. Hardening of existing control houses.

Response:

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

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

Docket No. E-7, Sub 1214

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

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

Request:

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

Response:

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

b. None.

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

b. None.

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

NCSEA DR-2-19.xlsx