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INFORMATION SHEET

PRESIDING: Chair Mitchell, Presiding; Commissioners Brown-Bland, Gray, Clodfelter, Duffley, Hughes, McKissick
PLACE: Held Via Videoconference
DATE: Wednesday, September 9, 2020
TIME: 9:00 a.m. to 12:47 p.m.
DOCKET NOS.: E-7, Sub 1213; E-7, Sub 1214; E-7, Sub 1187
COMPANY: Duke Energy Carolinas, LLC
DESCRIPTION: E-7, Sub 1213, In the Matter of Petition of Duke Energy Carolinas, LLC, for Approval of Prepaid Advantage Program; E-7, Sub 1214, In the Matter of Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina; E-7, Sub 1187, In the Matter of Application of Duke Energy Carolinas, LLC, for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricane Florence and Michael and Winter Storm Diego

VOLUME NUMBER: 16

APPEARANCES
(See attached.)

WITNESSES
(See attached.)

EXHIBITS
(See attached.)

COPIES ORDERED: Downey, Culpepper, Holt, Cummings, Edmondson, Grantmyre, Dodge, Jost, Little, Luhr, Force, Townsend, Robinson, Kells, Mehta, Lee, Cress, Ross, Ledford, Smith, Schauer, Heslin, Su, Crystal and Beverly
CONFIDENTIAL TRANSCRIPTS and EXHIBITS ORDERED: Robinson, Heslin, Somers, Kells, Jagannathan, Mehta, Lee, Cress, Ross, Jenkins, Beverly, Ledford, Smith, Crystal, Su, Force, Townsend, Downey, Schauer, Culpepper, Cummings, Dodge, Edmondson, Grantmyre, Holt, Jost, Little, and Luhr

REPORTED BY: Linda Garrett
TRANSCRIBED BY: Linda Garrett
DATE FILED: September 14, 2020

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PLACE: Held Via Videoconference REDACTED
DATE: Wednesday, September 9, 2020
TIME: 9:00 A.M. - 12:47 P.M.
DOCKET NO.: E-7, Sub 1214
E-7, Sub 1213
E-7, Sub 1187
BEFORE: Chair Charlotte A. Mitchell, Presiding
Commissioner ToNola D. Brown-Bland
Commissioner Daniel G. Clodfelter
Commissioner Lyons Gray
Commissioner Kimberly W. Duffley
Commissioner Jeffrey A. Hughes
Commissioner Floyd B. McKissick, Jr.

IN THE MATTER OF:
DOCKET NO. E-7, SUB 1214
In the Matter of
Application by Duke Energy Carolinas, LLC,
for Adjustment of Rates and Charges Applicable to
Electric Utility Service in North Carolina

DOCKET NO. E-7, SUB 1213

In the Matter of

Petition of Duke Energy Carolinas, LLC,

for Approval of Prepaid Advantage Program

DOCKET NO. E-7, SUB 1187

In the Matter of

Application of Duke Energy Carolinas, LLC,

for an Accounting Order to Defer Incremental Storm Damage Expenses Incurred as a Result of Hurricanes Florence and Michael and Winter Storm Diego

VOLUME 16

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I/A

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Dec 30 2016

December 30, 2016

VIA ELECTRONIC FILING

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

RE: Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order
Docket Nos. E-2, Sub 1103 and E-7, Sub 1110

Dear Ms. Jarvis:

Enclosed please find Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order, for filing in the above-referenced matter.

Please contact me if you have any questions.

Sincerely,

Heather Shirley Smith

Heather Shirley Smith

Enclosure

cc: Parties of Record

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CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Petition for an Accounting Order, in Docket Nos. E-2, Sub 1103 and E-7, Sub 1110, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid, properly addressed to parties of record.

This is the 30th day of December, 2016.

By: Heather Shirley Smith

Heather Shirley Smith
Deputy General Counsel
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Dec 30 2016

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. E-2, SUB 1103
DOCKET NO. E-7, SUB 1110

In the Matter of	)	
	)	
Joint Petition of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC for an Accounting Order to Defer Environmental Compliance Costs	)	**DUKE ENERGY PROGRESS, LLC AND DUKE ENERGY CAROLINAS, LLC PETITION FOR AN ACCOUNTING ORDER**

Pursuant to North Carolina Utilities Commission (the "Commission") Rules R1-5 and R8-27, Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies") respectfully petition the Commission to issue an accounting order for regulatory accounting purposes authorizing the Companies to defer in a regulatory asset account (until the Companies' next base rate cases) certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to Coal Combustion Residuals ("CCRs" or "coal ash").

Executive Summary

The Companies are making substantial progress in safely managing coal ash and closing ash basins across the Carolinas in compliance with state and federal law, and have been transparent about our accounting for all costs associated with this important work. In this Petition, the Companies do not seek a change in customer rates; rather, this Petition requests an accounting order such that the Companies' compliance costs may be deferred in a regulatory asset account for review in a future setting, such as a rate proceeding. Through such a proceeding, the Commission may consider such costs in broad scope, including such factors as (1) the prudency of the Companies' activities in complying with legal requirements; (2) the appropriate cost of service allocation; (3)

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earnings impact, and (4) the length of amortization schedule to mitigate rate impact.

Expenses incurred for state and federal compliance and requested for deferral (January 2015 - November 2016) include $434.4 million for DEC and $291.9 million for DEP. No fines or penalties, or costs associated with the Dan River pipe break repair and resulting spill cleanup, are included in these amounts nor will be sought for rate recovery at a later date.

Closing ash basins is part of the life cycle of the Companies' coal plants, and compliance with state and federal regulatory requirements is part of the normal operation of a utility. Costs related to the operation of a power plant, including decommissioning costs, are typically paid for by customers. Ultimately, the Commission will determine how costs associated with ash management and basin closure will be handled through the robust and public ratemaking process. As explained below, while recovery of this type of cost is consistent with the precedent in North Carolina, the magnitude, scope, duration and complexity of compliance is extraordinary and unprecedented. As such, the Companies respectfully request the relief granted in this Petition so that all complexities may be adequately reviewed by the Commission and stakeholders at an appropriate time.

In support of this Petition, the Companies respectfully present the Commission the following:

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Name and Address of Duke Energy Progress

1. The correct name and post office address of the Company are:

Duke Energy Progress, LLC
410 S. Wilmington Street, NCRH 20
Raleigh, North Carolina 27601

Name and Address of Duke Energy Carolinas

Duke Energy Carolinas, LLC
P.O. Box 1006
Charlotte, North Carolina 28201-1006

Notices and Communications

2. The names and addresses of the attorneys of the Companies who are authorized to receive notices and communications with respect to this petition are:

Heather Shirley Smith, Esq.
Deputy General Counsel
Duke Energy Corporation
40 W. Broad Street, Suite 690
Greenville, South Carolina 29601

and

Lawrence B. Somers, Esq.
Deputy General Counsel
Duke Energy Corporation
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Raleigh, North Carolina 27602-1151

Description of the Companies

3. DEP is engaged in the generation, transmission, distribution, and sale of electric energy at retail in portions of western, central, and eastern North Carolina and the eastern portion of South Carolina. DEP also sells electricity at wholesale to municipal, cooperative and investor-owned electric utilities, and its wholesale sales are subject to the jurisdiction of the Federal Energy Regulatory Commission. DEP is a public utility under

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the laws of North Carolina and is subject to the jurisdiction of this Commission with respect to its operations in this State. DEP is also authorized to transact business in the State of South Carolina and is a public utility under the laws of that State. Accordingly, its operations in that State are subject to the jurisdiction of the Public Service Commission of South Carolina.

4. DEC is engaged in the generation, transmission, distribution, and sale of electric energy at retail in the central and western portions of North Carolina and the western portion of South Carolina. DEC also sells electricity at wholesale to municipal, cooperative and investor-owned electric utilities, and its wholesale sales are subject to the jurisdiction of the Federal Energy Regulatory Commission. DEC is a public utility under the laws of North Carolina and is subject to the jurisdiction of this Commission with respect to its operations in this State. DEC is also authorized to transact business in the State of South Carolina and is a public utility under the laws of that State. Accordingly, its operations in that State are subject to the jurisdiction of the Public Service Commission of South Carolina.

Environmental Requirements

5. On April 17, 2015, the Environmental Protection Agency ("EPA") published in the Federal Register a rule to regulate the disposal of CCRs from electric utilities as solid waste. The federal regulation classifies CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act and allows beneficial use of CCRs with some restrictions. The regulation[1] applies to all new and existing landfills, new and existing surface impoundments, structural fills and CCR piles. The

[1] See Hazardous and Solid Waste Management System: Disposal of Coal Combustion Residuals from Electric Utilities, promulgated by the EPA and published on April 17, 2015, in 80 Fed Reg. 21302.

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federal CCR rule establishes requirements regarding landfill design; structural integrity design and assessment criteria for surface impoundments; groundwater monitoring and protection procedures; and other operational and reporting procedures to ensure the safe disposal and management of CCR. In addition to the requirements of the federal CCR regulations, CCR landfills and surface impoundments will continue to be independently regulated by the State through operating permits and environmental requirements.

6. In accordance with ASC 410-20, Asset Retirement and Environmental Obligations – Asset Retirement Obligations, each of DEC and DEP record an asset retirement obligation ("ARO") when there is a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. These accounting requirements dictate the measurement and recognition of AROs for companies in general. The Commission has also issued orders requiring the Companies to defer all impacts of other AROs until those costs can be considered in future rate making decisions.[2] In addition, DEP's rates currently include a component for ash remediation costs as a part of Cost of Removal included in depreciation rates; however, only a small balance has been collected for this matter since DEP's last retail rate case in North Carolina.

7. On September 20, 2014, the North Carolina Coal Ash Management Act ("CAMA"), 2014 N.C. Sess. Laws 122; 2014 N.C. Ch. 122; 2013 N.C. SB 729, became law and was amended on June 24, 2015, by the Mountain Energy Act, which established

[2] In the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account, NCUC Docket No. E-7, Sub 723, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 8, 2003); and In the Matter of Carolina Power & Light Company's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account, NCUC Docket No. E-2, Sub 826, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 12, 2003).

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a Coal Ash Management Commission ("Coal Ash Commission") to oversee handling of coal ash within the State. Through CAMA, the legislature:

(i) prohibited construction of new and expansion of existing ash impoundments and use of existing impoundments at retired facilities;

(ii) required closure of ash impoundments at Duke Energy Progress' Sutton Plant and Duke Energy Carolinas' Riverbend and Dan River stations no later than August 1, 2019 and Duke Energy Progress' Asheville Plant no later than August 1, 2022;

(iii) required dry disposal of fly ash at active plants, excluding the Asheville Plant, not retired by December 31, 2018;

(iv) required dry disposal of bottom ash at active plants, excluding the Asheville Plant, by December 31, 2019, or retirement of active plants;

(v) required all remaining ash impoundments in North Carolina be categorized as high-risk, intermediate-risk or low-risk no later than December 31, 2015 by the North Carolina Department of Environmental Quality ("DEQ", formally known as the North Carolina Department of Environmental and Natural Resources, or "DENR") with the method of closure and timing to be based upon the assigned risk, with closure no later than December 31, 2029;

(vi) established requirements to deal with groundwater and surface water impacts from impoundments; and

(vii) enhanced the level of regulation for structural fills utilizing coal ash.

CAMA included a variance procedure for compliance deadlines and modification of requirements regarding structural fills and compliance boundaries. Duke Energy has and

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will periodically submit to DEQ site-specific coal ash impoundment closure plans or excavation plans in advance of closure. These plans and all associated permits must be approved by DEQ before any excavation or closure work can begin. CAMA leaves the decision on cost recovery determinations related to closure of CCR surface impoundments (ash basins or impoundments) to the normal ratemaking processes before utility regulatory commissions. Accordingly, this deferral request will allow the recoverability of these costs to be determined in the context of formal proceedings when rate changes are sought by the Companies.

8. In September 2014, Duke Energy Carolinas executed a consent agreement with the South Carolina Department of Health and Environmental Control ("SCDHEC") requiring the excavation of an inactive ash basin and ash fill area at the W.S. Lee Steam Station. As part of this agreement, in December 2014, Duke Energy Carolinas filed an ash removal plan and schedule with SCDHEC. In April 2015, the federal CCR rules were published, and Duke Energy Carolinas subsequently executed an agreement with the conservation groups Upstate Forever and Save Our Saluda requiring Duke Energy Carolinas to remediate all active and inactive ash storage areas at the W.S. Lee Steam Station. Coal-fired generation at W.S. Lee ceased in 2014, and unit 3 is being converted to natural gas. In July 2015, Duke Energy Progress executed a consent agreement with SCDHEC requiring the excavation of all CCRs at the Robinson Plant site within eight years. The W.S. Lee Station site and the Robinson Plant are required to be closed pursuant to the recently issued CCR rule and/or the provisions of these consent agreements which are consistent with the federal CCR closure requirements described above.

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9. CAMA was amended by NC House Bill 630, the Drinking Water Protection and Coal Ash Cleanup Act, which was signed into law by the Governor of North Carolina on July 14, 2016 (the "CAMA Amendment"). The CAMA Amendment imposes requirements on Duke Energy that, if fulfilled, allow Duke Energy more closure options that may be implemented over a longer period of time. The CAMA Amendment requires Duke Energy to provide a permanent water supply to residents with drinking water supply wells located within ½ mile of Duke Energy ash basins and to certain other potentially impacted residents. Additionally, the CAMA Amendment requires Duke Energy to undertake dam improvement projects. Upon satisfactory completion of the dam improvement projects and installation of alternate drinking water sources by October 15, 2018, the legislation requires the DEQ to reclassify sites proposed as intermediate risk (excluding H.F. Lee, Cape Fear and Weatherspoon plants as discussed below), as low risk. The CAMA Amendment also requires excavation of the basins at three DEP facilities (Cape Fear, H.F. Lee, and Weatherspoon stations) based on their statutory classification as "intermediate." Closure of these specific intermediate basins is required to be completed no later than August 1, 2028. Finally, the CAMA Amendment requires the installation and operation of three large-scale coal ash beneficiation projects which are expected to produce reprocessed ash for use in the concrete industry. Closure of basins at sites with these beneficiation projects are required to be completed no later than December 31, 2029. On October 5, 2016, Duke Energy announced Buck Steam Station as a first location for one of the beneficiation projects. On December 13, 2016, Duke Energy Progress announced plans to excavate coal ash from four basins at the H.F. Lee

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Plant in Goldsboro, N.C., and to safely recycle the valuable material for use in concrete products.

10. In March 2016, the Coal Ash Management Commission created by the CAMA Amendment was disbanded by the Governor of North Carolina based on a North Carolina Supreme Court ruling regarding the constitutionality of the body.[3] The CAMA Amendment eliminates the Coal Ash Management Commission and transfers responsibility for ash basin closure oversight to the DEQ.

11. AROs recorded on the DEC and DEP Condensed Consolidated Balance Sheets at September 30, 2016 are based upon the legal obligation for closure of coal ash basins and the disposal of related CCRs as a result of the federal and state requirements described above in paragraph 5 in the amount of approximately $2.1 billion for DEC, and approximately $2.4 billion for DEP. Since the initial recognition of these AROs, the Companies have deferred all of the accounting impacts of these obligations for future determination in the next rate case with the exception of items for which a specific recovery mechanism has been established (such as limited recovery for ash reuse through the fuel clauses in North Carolina for DEC and DEP).

12. Accordingly, the total value of the Companies' AROs recorded as of September 30, 2016 related to coal ash basin closure costs to date is approximately $4.5 billion. These AROs are included in the Companies' financials as required by NCUC Docket No. E-7, Sub 723, Order dated August 8, 2003, and NCUC Docket No. E-2, Sub 826, Order dated August 12, 2003. The actual compliance costs incurred may be materially different from these estimates based on the timing and requirements of the

[3] *McCrory v. Berger*, 769 S.E.2d 629, 368 N.C. 253, (N.C. 2015).

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final regulations. The Companies spent $434.4 million (DEC) and $291.9 million (DEP) in the period January 1, 2015 through November 30, 2016, related to the AROs.

13. In particular, DEC spent $434.4 million on the following activities: engineering and regulatory compliance activities for all sites; mobilization and start-up of closure activities at Dan River Steam Station and Riverbend Steam Station; building rail infrastructure for basin excavation at Dan River Station; dewatering activities associated with basin closure at Dan River, W.S. Lee and Riverbend stations; and ash excavation at Dan River, W.S. Lee, Cliffside and Riverbend stations of approximately 2.7 million tons.[4]

14. In particular, DEP spent $291.9 million on the following activities: engineering and regulatory compliance activities for all sites; mobilization and start-up of closure activities at Asheville and Sutton plants; building rail infrastructure for ash excavation at Sutton Plant; dewatering activities associated with basin closure at Asheville, Sutton, H.F. Lee and Cape Fear plants; ash excavation at Asheville and Sutton plants of approximately 1.8 million tons; and closure of the 1982 ash basin at Asheville Plant.

Financial Consequences of this Request

15. The Companies have been accounting for the ash basin AROs and expense in the manner detailed in the informational filing made to the Commission on December 21, 2015, which was docketed as Docket Nos. E-2, Sub 1103 and E-7, Sub 1110. That filing is attached to this Petition as Attachment 1. As explained in that filing, the Companies did not file a deferral request at that time due to significant litigation and

[4] Again, no fines, penalties or Dan River pipe break repair or spill cleanup costs are included in these amounts.

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reconsiderations related to CAMA, the now-defunct Coal Ash Management Commission, and numerous other outstanding issues that have now been resolved sufficiently, including the passage of the CAMA Amendment, such that the Companies may make this request.

16. The Companies' accounting practices, consistent with generally accepted accounting principles, have resulted in preserving the issue for this Petition. As such, the expense effect of the expenditures incurred from January 1, 2015 to date has been captured in ARO accounting, and the Company's earnings do not reflect the expenses to date.

17. In a recent order, the Commission articulated its general proposition that in assessing the financial consequences of a deferral request as measured by impact to return on equity ("ROE"), adjustments to per-book ROEs should be considered, as well as "noteworthy facts, circumstances, and/or events significantly affecting those ROEs."[5] The Companies show such noteworthy circumstances below, including showing what the ROEs would be if the Commission nullifies the accounting treatment reported to the Commission in these Dockets.

18. DEP reported returns on equity in its E.S.-1 surveillance reports of 10.39% for the 12 months ended September 30, 2016, for its North Carolina retail jurisdiction. The below table shows what these ROEs would be if adjusted for several ratemaking adjustments typically made in a general rate case. The below table also shows the effect of denying this deferral request.

[5] In the Matter of Application by Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Accounting Order to Defer Certain Capital and Operating Costs Associated with the Warren County Combined Cycle Addition, *Order Denying Deferral Accounting for Warren County Combined Cycle Generating Facility*, Docket No. E-22, Sub 519 (March 29, 2016) (see generally pp 12-13 and 25).

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		12 Months Ended 9/30/2016
		ROE
1	**As Reported in E.S.-1**	10.39%
2	**Adjust Equity Ratio to Last Approved**	0.06%
3	**Normalize Weather**	-0.11%
4	**Remove DSM/EE PPI Incentive**	-0.27%
5	**Remove One Time Items**	0.20%
6	**Adjust to End of Period Rate Base, incl Interest Sync**	-0.05%
7	**Annualize Depreciation Expense, incl adjusted to Depreciation Reserve**	-0.31%
8	**Adjusted ROE**	9.91%
9	**Impact of Not Approving Coal Ash Deferral**	-2.44%
10	**Adjusted ROE if Deferral Not Approved**	7.47%

DEP's authorized return on equity is 10.2%. Thus, absent approval of this request, DEP's return on equity for its North Carolina retail operations is expected to be well below the return last authorized by the Commission.

19. DEC reported returns on equity in its E.S.-1 surveillance reports of 10.33% for the 12 months ended September 30, 2016 for its North Carolina retail jurisdiction. The below table shows what these ROEs would be if adjusted for several ratemaking adjustments typically made in a general rate case. The below table also shows the effect of denying this deferral request.

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		Twelve Months Ended 9/30/2016
		ROE
1	**As Reported in E.S.-1**	10.33%
2	**Adjust Equity Ratio to Last Approved**	0.40%
3	**Normalize Weather**	-0.41%
4	**Remove DSM/EE PPI Incentive**	-0.22%
5	**Remove One Time Items**	0.07%
6	**Adjust to End of Period Rate Base, incl Interest Sync**	0.04%
7	**Annualize Depreciation Expense, incl adjusted to Depreciation Reserve**	-0.13%
8	**Adjusted ROE**	10.08%
9	**Impact of Not Approving Coal Ash Deferral**	-2.47%
10	**Adjusted ROE if Deferrals Not Approved**	7.61%

DEC's authorized return on equity is 10.2%. Thus, absent approval of this request, DEC's return on equity for its North Carolina retail operations is expected to be well below the return last authorized by the by the Commission.

20. Both DEP and DEC intend to file for a general rate case in North Carolina within the next 12 months to address the prudency and ratemaking effects of the costs at issue in this Petition.

21. Approval of this deferral request will benefit the Companies and customers by helping to assure investor confidence in DEP and DEC and help assure access to needed capital on reasonable terms.

Deferral Request

22. The actual costs incurred to comply with the federal and state regulations will be deferred to a regulatory asset (Account 182.3) including a carrying charge of a

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debt and equity return at the Companies' approved weighted average cost of capital, if approved by the Commission. The Companies are requesting to defer to a regulatory asset, until the effective date of new rates from the next base rate case, all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs related to activities required under the legislative and regulatory mandates outlined in paragraphs five and seven.[6] The Companies are also requesting to defer a cost of capital on the deferred costs at the weighted average cost of capital. The Companies propose providing support for expenditures made to meet the requirements of the legislative and regulatory mandates outlined to the Commission and interested parties in retail base rate cases filed within the next twelve months.

23. Absent the deferral, the Companies may have to write off billions of dollars of costs for accounting purposes, which without question would severely impair the Companies' financial stability and ability to attract capital on reasonable terms.

24. The Companies believe that this request is consistent with the case law and policy in this State of allowing unique regulatory treatment for environmental compliance costs. For example, in Docket Nos. G-9, Sub 495 and G-21, Sub 457, the Commission authorized an ongoing deferral for compliance costs for gas pipeline integrity regulation until the next rate case, subject to a subsequent determination that the costs were prudently incurred and properly accounted for, as well as a determination as to the proper method of recovery.[7] The Commission has also authorized deferral and

[6] These amounts would include any amounts recovered pursuant to NC General Statute 62-133.2.

[7] In the Matter of Application of Piedmont Natural Gas Company, Inc. for Approval of Deferred Accounting Treatment of Interim Pipeline Integrity Management Regulation Compliance Costs, *Order Approving Deferred Accounting Treatment*, Docket Nos. G-9, Sub 495 and G-21, Sub 457 (December 2, 2004).

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recovery of environmental remediation expenses. Specifically, the Commission has allowed recovery for Manufactured Gas Plant ("MGP") sites. See generally Docket Nos. G-5, Sub 327 and 495 related to environmental remediation costs incurred by the Public Service Company of North Carolina.[8] Most recently, the Commission has allowed recovery and ongoing deferral of ash basin closure costs by Dominion North Carolina Power in Docket No. E-22, Sub 532.[9]

25. As the Companies have previously committed, no fines, penalties or Dan River pipe break repair or spill cleanup costs will be included in the regulatory asset account requested in this Petition. Additionally, no fines or penalties associated with ash-related settlements reached with DENR or the EPA or any other state or federal agency will be included in such regulatory asset account.

26. The Companies request this deferral for costs incurred after January 1, 2015.

CONCLUSION

WHEREFORE, Duke Energy Progress and Duke Energy Carolinas respectfully request that the Commission allow them to establish a regulatory asset account for the deferral of all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs related to activities required under the legislative and regulatory mandates outlined in paragraphs five and seven. The

[8] In the Matter of Application of Public Service Company of North Carolina, Inc., for an Adjustment in its Rates and Charges, *Order Granting Partial Rate Increase,* Docket No. G-5, Sub 327 (October 7, 1994); and In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in its Rates and Charges, *Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting,* Docket No. G-5, 495 (October 24, 2008)(see p. 14).

[9] In the Matter of Application of Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina, *Order Approving Rate Increase and Cost Deferrals and Revising PJM Regulatory Conditions*, Docket No. E-22, Sub 532 (December 22, 2016) (see pp 62 and 63).

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Companies are also requesting to defer a cost of capital on the deferred costs at the weighted average cost of capital. The deferral would include these costs from January 1, 2015 until the approval of new rates in the Companies' next base rate cases before this Commission, to be filed within the next twelve months.

Respectfully submitted this 30th day of December, 2016.

DUKE ENERGY PROGRESS, LLC

DUKE ENERGY CAROLINAS, LLC

BY: Heather Shirley Smith

Heather Shirley Smith
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DUKE ENERGY.

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December 21, 2015

Ms. Gail L. Mount
Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4325

RE: Explanation of Accounting Treatment Related to Coal Ash Basin Obligations

Dear Ms. Mount:

Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") (collectively, the "Companies") respectfully notify the Commission of certain accounting entries, which are consistent with Generally Accepted Accounting Principles ("GAAP"), Federal Energy Regulatory Commission ("FERC") Uniform System of Accounts and General Instruction No. 25, and regulatory accounting practices related to the establishment of certain Asset Retirement Obligations ("AROs") associated with federal and state requirements related to coal ash management and ash basin closure costs. The Companies also notify the Commission of their treatment of actual expenditures related to compliance with such federal and state requirements, and the establishment of a regulatory asset for such expenditures.

Description of Requirements Giving Rise to the AROs

In accordance with Financial Accounting Standards Board ("FASB") Accounting Standards Codification for Asset Retirement and Environmental Obligations ("ASC 410-20")

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and FERC General Instruction No. 25, each of the Companies records an ARO when it has a legal obligation to incur retirement costs associated with the retirement of a long-lived asset and the obligation can be reasonably estimated. These accounting requirements dictate the measurement and recognition of AROs for companies in general. The Commission has issued orders allowing the Companies to defer all impacts of establishing an ARO until these costs can be considered in future rate making decisions.[1] In addition, DEP's rates currently include a component for ash remediation costs as a part of Cost of Removal included in depreciation rates; however, only a small balance has been collected for such costs since DEP's last retail rate case in North Carolina.

In April 2015, the Environmental Protection Agency ("EPA") published in the Federal Register a rule to regulate the disposal of Coal Combustion Residuals ("CCRs") from electric utilities as solid waste.[2] The federal regulation classifies CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act and allows beneficial use of CCRs with some restrictions. The federal regulation applies to all new and existing landfills, new and existing surface impoundments, structural fills and CCR piles. The federal regulation establishes requirements regarding landfill design, structural integrity design and assessment criteria for surface impoundments, groundwater monitoring and protection procedures and other operational and reporting procedures to ensure the safe disposal and management of CCR. In addition to the

[1] *In the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, NCUC Docket No. E-7, Sub 723, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 8, 2003); and *In the Matter of Carolina Power & Light Company's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account*, NCUC Docket No. E-2, Sub 826, *Order Granting Motion for Reconsideration and Allowing Deferral of Costs* (August 12, 2003).

[2] Hazardous and Solid Waste Management system: Disposal of Coal Combustion Residuals from Electric Utilities promulgated by the United States Environmental Protection Agency ("EPA") and published on April 17, 2015, 80 Fed Reg. 21302 ("CCR rule").

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requirements of the federal CCR regulation, CCR landfills and surface impoundments will continue to be independently regulated by most states, including North Carolina.

In September 2014, the North Carolina Coal Ash Management Act (the "Coal Ash Act") 2014 N.C. Sess. Laws 122; 2014 N.C. Ch. 122; 2013 N.C. SB 729, became law and was amended in June 2015, by the Mountain Energy Act. The Coal Ash Act, as amended,

(i) establishes a Coal Ash Management Commission ("Coal Ash Commission")[3] to oversee handling of coal ash within the state;

(ii) prohibits construction of new and expansion of existing ash impoundments and use of existing impoundments at retired facilities;

(iii) requires closure of ash impoundments at DEP's Sutton Plant and DEC's Riverbend and Dan River stations no later than August 1, 2019 and DEP's Asheville Plant no later than August 1, 2022;

(iv) requires dry disposal of fly ash at active plants, excluding the Asheville Plant, not retired by December 31, 2018;

(v) requires dry disposal of bottom ash at active plants, excluding the Asheville Plant, by December 31, 2019, or retirement of active plants;

(vi) requires all remaining ash impoundments in North Carolina to be categorized as high-risk, intermediate-risk or low-risk no later than December 31, 2015 by the North Carolina Department of Environment Quality ("DEQ," formally known as the NC Department of Environmental and Natural Resources, or "DENR") with the method of closure and timing to be based upon the assigned risk, with closure no later than December 31, 2029;

(vii) establishes requirements to deal with groundwater and surface water impacts from impoundments; and

(viii) enhances the level of regulation for structural fills utilizing coal ash.

[3] The structure of the Coal Ash Commission has been challenged as a violation of the constitutional separation of powers between the Executive Branch and the General Assembly. A decision by the N.C. Supreme Court is pending. Depending on the result, the decision could place doubt on previous actions by the Coal Ash Commission.

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The Coal Ash Act includes a variance procedure for compliance deadlines and modification of requirements regarding structural fills and compliance boundaries. The Companies have and will periodically submit to DEQ site-specific coal ash impoundment closure plans or excavation plans in advance of closure. These plans and all associated permits must be approved by DEQ before any excavation or closure work can begin.

In 2014 and 2015, DEC executed consent agreements with the South Carolina Department of Health and Environmental Control ("SCDHEC") and conservation groups requiring the excavation of an inactive ash basin and ash fill area at the W.S. Lee Steam Station. In July 2015, DEP executed a consent agreement with the SCDHEC requiring the excavation of an inactive ash fill area at the Robinson Plant within eight years. The W.S. Lee Station site and the Robinson Plant are required to be closed pursuant to the recently issued federal CCR rule and/or the provisions of these consent agreements which are consistent with the federal CCR closure requirements described above.

Accounting for Coal Ash Basin AROs

AROs are legal obligations associated with the retirement of a tangible long-lived asset that results from the acquisition, construction, or development and (or) the normal operation of a long-lived asset and also include environmental remediation liabilities that result from the normal operation of a long-lived asset and that is associated with the retirement of that asset. AROs recorded on the DEC and DEP Balance Sheets at November 30, 2015 are based upon the legal obligation for closure of coal ash basins and the disposal of related ash as a result of the federal and state requirements described above, and total approximately $1.84 billion for DEC and approximately $2.13 billion for DEP. These AROs are included in the Companies' financials as allowed by NCUC Docket No. E-7, Sub 723, Order dated August 8, 2003 and

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NCUC Docket No. E-2, Sub 826, Order dated August 12, 2003. The actual compliance costs incurred may be materially different from these estimates based on the timing and requirements of the final regulations.

Liabilities Recorded Related to the AROs

The Companies measure and recognize AROs in accordance with ASC 410-20 (previously Statement of Financial Accounting Standards "SFAS" No. 143). ASC 410-20 requires that the fair value of a liability for an ARO be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. As such, the coal ash ARO liability balance as of November 30, 2015 is based on the initial liability recognized in September 2014 upon the passage of the Coal Ash Act, as adjusted for accretion expense (discussed further below), cash settlements, and remeasurements of the liability. Remeasurements to the liability are due to revisions in either the timing or the amount of the original estimate of undiscounted cash flows. Typically, remeasurements occur when there are significant new events and information (e.g., passage of the federal CCR regulation, changes to closure plans, etc.) used by management in the estimation of future expected cash outflows.

The ARO was initially calculated, along with subsequent remeasurements and additions to the liability, using an expected present value technique of probability weighted discounted cash flows. These cash flows were based on management's best estimate of projected cash flows and legal interpretation of the various federal and state requirements described above. As the obligations can be satisfied by various compliance alternatives selected based on management's site-specific risk assessments over various timeframes, the uncertainty surrounding the obligations was factored into the ARO recognition by assessing the likelihood (probability) that a certain type of compliance method would be required.

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These estimated cash flows, along with various other financial assumptions required by ASC 410-20 (including inflation and discount rates, profit margin and risk premium) were used to properly measure the AROs on the balance sheet at fair value, as defined by GAAP.

Because the liability is based on a present value calculation using many assumptions, including a credit-adjusted risk-free discount rate, the liability will grow simply from the passage of time. This increase to the liability is known as accretion. From January 1, 2015 to November 30, 2015, accretion totaled $59 million and $65 million for DEC and DEP, respectively.

Assets Associated with the Liability Recorded Related to the AROs

At the time the ARO liability is recorded, a corresponding and equivalent ARO asset is recorded on the books, as part of the cost of the associated coal plant in the property, plant and equipment ("PP&E") accounts, or if associated with a retired coal plant, recorded in regulatory assets. The ARO PP&E balance is depreciated over the remaining estimated plant lives, and such depreciation expenses is deferred into regulatory asset accounts. From January 1, 2015 to November 30, 2015, ARO depreciation totaled $217 million and $325 million for DEC and DEP, respectively. Additionally, as discussed above, accretion is added to the ARO liability each reporting period to account for the time value of money, so that at the time of retirement, the recorded ARO liability will be sufficient to provide for the cash outlays necessary to meet the legal obligation. Thus, the ARO expense recorded each year generally includes two components: depreciation expense associated with the ARO asset on active plants and accretion expense measuring the change in the total ARO liability due to the time value of money. Consistent with the requirements of the Commission's Order dated August 8, 2003 in Docket No. E-7, Sub 723 and Order dated August 12, 2003 in Docket No. E-2, Sub 826, all income statement impacts related to AROs ultimately reside in regulatory asset accounts.

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The FASB recognized that differences may exist between the requirements of ASC 410-20 and the treatment of ARO cost for regulatory purposes, and accordingly, provided that a regulated entity subject to ASC 980, *Regulated Operations*, (formerly SFAS 71, *Accounting for the Effects of Certain Types of Regulation*), could recognize a regulatory asset or liability for any differences between the two approaches, if the facts and circumstances meet the requirements of ASC 980 for such recognition.

Net Asset Balance Primarily Relates to Cash Expenditures

As of November 30, 2015, PP&E (active plants) and regulatory assets (inactive plants) related to coal ash basin AROs total approximately $4.19 billion, combined for both categories of assets and DEC and DEP. The related asset retirement obligation liabilities total approximately $3.97 billion, resulting in a net asset balance of approximately $220.5 million. Of this amount, $231.9 million relates to cash expenditures incurred in 2015 associated with ash basin closure, and $2.7 million relates to carrying costs, partially offset primarily by recoveries through existing DEP cost of removal rates.

As a result of the deferral accounting applied to this ARO liability, actual costs incurred to comply with the federal and state regulations regarding closure of ash basins are being deferred. As coal ash basin closure compliance costs are incurred, the Companies are reducing the ARO liability and the associated ARO regulatory asset described above, while simultaneously creating a corresponding separate regulatory asset that represents actual cash expenditures incurred. As the Companies are excluding all associated coal ash ARO deferrals for earnings surveillance reporting and are funding these expenditures with its debt and equity capitalization, the Companies are recording a debt and equity return ("carrying charge") on the aforementioned net asset for regulatory purposes. GAAP requires the equity return to be

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deferred (i.e., not recognized) until rate recovery has begun, and thus the only carrying charge recorded to date for GAAP purposes is the debt return, which totals approximately $2.7 million combined for the Companies through November 30, 2015. Ultimately, only actual costs resulting in cash outlays by the Companies related to ash basin closure, plus carrying charges, will result in amounts for which the Companies will request accounting and recovery treatment in future filings before this Commission. Coal ash basin costs that relate to activities outside the scope of the aforementioned legally required activities (e.g., Federal CCR rules and the NC CAMA legislation) are being expensed immediately as Operations and Maintenance ("O&M") expense. In addition, capital conversion costs such as those related to conversion to dry or fly ash equipment are recorded in Construction Work in Progress.

The Companies do not seek any further specific accounting approval at present due to the uncertainties in North Carolina regarding the closure costs of coal ash basins. Actual costs to be incurred will be dependent upon factors that vary from site to site. The most significant factors are the method and time frame of closure at the individual sites. Closure methods considered include removing the water from the basins and capping the ash with a synthetic barrier, excavating and relocating the ash to a lined structural fill or lined landfill, or recycling the ash for concrete or some other beneficial use. Under the previously cited Coal Ash Act, DEQ is required to prioritize sites by December 31, 2015. That process has not been completed. Once the DEQ determinations are made, the Companies will need to evaluate the recommendation and develop more specific cost estimates. The ultimate method and timetable for closure will be in compliance with standards set by the EPA rule and any state regulations. The ARO estimates will be adjusted as additional information is gained through the closure process, including acceptance and approval of compliance approaches which may change management

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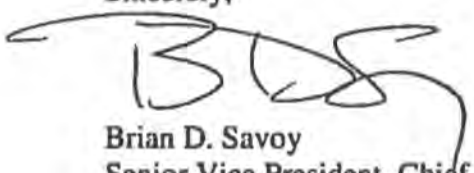
assumptions, and may result in a material change to the recorded ARO. In addition, on March 5, 2015, Governor McCrory filed a lawsuit challenging the constitutionality of the Coal Ash Commission. That case is currently pending before the North Carolina Supreme Court.[4] Pending a decision in that case, activity by the Coal Ash Commission has been suspended. Further, if the Court should rule that the actual structure of the Coal Ash Commission violates the constitutional provision of the separation of powers, the lawfulness of previous actions by the Commission could be subject to legal challenge.

The Companies provide this explanation of their accounting for the above-described ash basin closure and compliance costs for the Commission's information at this time. At a later date, when there is sufficient clarity in North Carolina regarding the closure of ash basins, the Companies will bring this matter before the Commission for ultimate disposition.

If you have any questions, please let me know.

Sincerely,



Brian D. Savoy
Senior Vice President, Chief Accounting Officer and Controller

cc: Antoinette R. Wike
Christopher J. Ayers
Chairman Edward S. Finley, Jr
Commissioner Don M. Bailey
Commissioner Bryan E. Beatty
Commissioner ToNola D. Brown-Bland
Commissioner Jerry C. Dockham
Commissioner James G. Patterson
Commissioner Susan Warren Rabon

[4] *Patrick L. McCrory, et al v. Phillip E. Berer, et al. NC Supreme Court*, Case No. 113A15 (2015).

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-7, SUB 723

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account	)))))	ORDER GRANTING MOTION FOR RECONSIDERATION AND ALLOWING DEFERRAL OF COSTS

BY THE COMMISSION: On May 20, 2003, Duke Power, a Division of Duke Energy Corporation (Duke or Company), filed a motion requesting that the Commission reconsider that portion of its Order issued April 4, 2003, in the above-referenced docket, which denied Duke's request to defer the forward-requirements impact of the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (SFAS 143) and, instead, grant such request.

BACKGROUND

Duke's initial petition was filed on January 10, 2003. It concerned a request for authority to place certain Asset Retirement Obligation (ARO) costs in deferred accounts. Duke stated that such authority was needed so that its financial statements will continue to reflect the current regulatory treatment for these costs and will not be altered due to Duke's adoption of SFAS 143.

As explained by Duke in its initial petition, in June 2001, the FASB issued SFAS 143, effective for fiscal years beginning after June 15, 2002. SFAS 143, which must be implemented by Duke in order to comply with generally accepted accounting principles (GAAP), mandates a new method for measuring and accounting for certain AROs. Those obligations, as defined by SFAS 143, concern legal obligations associated with the retirement of tangible, long-lived assets. Duke indicated that it expected that the only significant retirement costs constituting AROs subject to SFAS 143 would be its obligations to decommission the radiated portions of its nuclear plants and environmental clean-up at its Belews Creek Coal-fired Steam Plant; although according to Duke, other AROs may exist.

If a legally enforceable ARO, as defined by SFAS 143, is deemed to exist for a firm, a liability for the ARO must be measured and recorded on the firm's books in the period in which it is incurred. The liability must be recorded at fair value, that is, the

amount that the firm would pay in the market to settle the liability. If market prices are not available, estimates of fair value can be calculated by discounting the estimated cash flows associated with the ARO to their present value at the date the liability is to be recorded.

At the time the liability is recorded, a corresponding and equivalent ARO asset is recorded on the firm's books, as part of the cost of the associated tangible asset. The ARO asset is depreciated over the life of the associated long-lived asset. Additionally, an accretion is added to the ARO liability each reporting period to account for the time value of money, so that at the time of retirement the recorded ARO liability will be sufficient to provide for the cash outlays necessary to meet the legal obligation. Thus, the ARO expense recorded each year during the life of the tangible asset generally includes two components: depreciation expense associated with the ARO asset and accretion expense measuring the change in the ARO liability due to the time value of money. The ARO liability and associated ARO asset may also change over time due to revisions in the timing or the amount of the original estimate of ARO costs. Such changes can affect the recorded expense in the period of change and/or future periods.

In addition to the forward-looking requirements of SFAS 143 described above, firms are also required to recognize the cumulative impact in the financial statements in the year of its implementation. This cumulative impact amounts to a "catch-up" entry on the firm's books, so that in future years the financial statements will appear as if the requirements of SFAS 143 had always been followed.

The FASB recognized that differences may exist between the requirements of SFAS 143 and the treatment of ARO costs for regulatory purposes, and accordingly, provided that a regulated entity subject to Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (SFAS 71), could recognize a regulatory asset or liability for any differences between the two approaches, if the facts and circumstances meet the requirements of SFAS 71 for such recognition.

In its initial Petition, Duke requested that the Commission authorize it to place all income statement impacts arising from the Company's adoption of Statement 143 in regulatory deferred accounts. The amounts proposed to be deferred included both the net cumulative/catch-up and the forward-requirements impacts.

By Order issued April 4, 2003, the Commission granted the Company's request to defer the cumulative impact of SFAS 143, subject to certain conditions. However, Duke's request to defer the forward-requirements impact of SFAS 143 was denied.

In denying the request to defer the forward-requirements impact, the Commission stated that "[i]t simply cannot be determined from the record that the forward-requirements represent major expenditures or that they otherwise satisfy a condition of the Clean Smokestacks Bill [Bill] such that the Commission would have the authority to allow def`rral of those costs as an exception to the rate freeze." The Bill, in particular G.S. 62-133.6(e), provides that, during the period of the rate freeze,

June 20, 2002, through December 31, 2007, the Commission may allow the deferral of costs or revenues by a utility if the utility experiences "governmental action resulting in significant cost reductions or requiring major expenditures including but not limited to the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs."

MOTION FOR RECONSIDERATION

In its motion for reconsideration, Duke stated that the requirements of SFAS 143 do not only include Duke's reflection of a cumulative amount on its income statement as an expense in the year of implementation of SFAS 143, but also an ongoing obligation to reflect all ongoing differences between ARO expenses recorded as required under SFAS 143 and those recorded as determined under the Commission's historical method. Duke, after having opined that SFAS 143 constituted a single "governmental action," submitted that the Commission should have viewed the impacts of the cumulative requirement and the forward-requirements in totality rather than individually, as it did in reaching its conclusion that Duke's request regarding the forward-requirements impact should be denied.

Duke stated that, if the cumulative requirement is "undoubtedly" a major expenditure, as the Commission found in the Order, then it follows that the forward-requirements impact only enhances the magnitude of the impact of the cumulative requirement. Therefore, according to Duke, regardless of the magnitude of the resulting expenditures of the forward-requirements, their deferral is appropriate under the Bill. Thus, according to Duke, it is unnecessary for the Commission to determine whether the forward-requirements impact viewed in isolation, represents major expenditures or otherwise satisfies a condition of the Bill, such that the Commission would have the authority to allow deferral of those costs as an exception to the rate freeze.

Duke noted that the Commission correctly found in the Order that:

> Not only should Duke's rates reflect the Commission's decisions . . . its financial statements, including reports to this Commission, should also clearly reflect and adequately disclose the economic consequences of the Commission's actions. If the present deferral request is not allowed, the FASB will have, effectively, usurped the Commission's authority in regard to the establishment of the appropriate level of ARO costs properly includable as an operating revenue deduction for financial reporting purposes with respect to the Company's North Carolina retail operations. That result, however, is avoided to the maximum extent possible as a result of the Commission having approved deferral of the cumulative impact of SFAS 143. That result is, unmistakably, appropriate. *The foregoing reasoning, of course, applies equally to that part of the petition which the Commission has denied, i.e., the Company's request for*

deferral of the forward-requirements of SFAS 143. (Emphasis added in original.)

Duke argued that, for the reasons stated above and based on the Commission's own findings as quoted above, it is inappropriate to view the forward-requirements impact of SFAS 143 in isolation in evaluating whether Duke's request meets the elements of the deferral provisions of the Bill. Nevertheless, Duke averred that the magnitude of the amounts contained in the confidential information provided as Attachment A to its motion for reconsideration supports approval of Duke's deferral of the forward-requirements impact of SFAS 143. Attachment A, which was filed under confidential seal, presents a calculation of the differences between decommissioning costs under SFAS 143 and such costs determined in accordance with the Commission's past decisions for the five-year period ending December 31, 2007.

Duke stated that the impacts of the forward-requirements are likely to fluctuate over time because they are dependent on, among other things, the earnings of Duke's nuclear decommissioning funds and the amount of accretion expense. Duke noted that the funds earnings rates used in the calculation of the differences described above - i.e., in the calculation of the estimated deferral amounts – assumes the funds' annual earnings will equal the annual averages of the last five years of Duke's actual funds earnings rates.

Finally, Duke commented that, in addition to the impact of prospectively changing to SFAS 143 for the legal asset retirement obligations, disallowance of deferral accounting for the forward-requirements impact may result in accounting changes for nonlegal asset retirement obligations that are currently being accounted for through Commission approved depreciation rates. Examples of nonlegal asset retirement obligations are the costs of removal of distribution, transmission, and nonnuclear generation facilities. Duke stated that it does not believe that the Commission intended to modify current depreciation rates or the accounting for cost of removal in the Order and respectfully requested the Commission to clarify that it did not intend to modify Duke's current depreciation rates or the accounting for cost of removal for nonlegal obligations.

In summary, Duke requested that the Commission reconsider its April 4, 2003 Order denying the Company's request to defer the forward-requirements impact of SFAS 143 and, on consideration of the additional information provided, allow the deferral of that impact. Duke also requested that the Commission clarify that no modification of Duke's current depreciation rates or accounting for cost of removal was intended by the Order.

COMMENTS

On May 27, 2003, the Commission issued an Order requesting comments on Duke's motion for reconsideration. On June 6, 2003, Carolina Utility Customers

Association, Inc. (CUCA), Attorney General Roy Cooper (Attorney General), and the Public Staff – North Carolina Utilities Commission (Public Staff) filed comments.

CUCA, in its comments, opposed the deferral of the forward-requirements impact of SFAS 143 and asked the Commission to deny Duke's motion for reconsideration. CUCA opined that a "mere expectation or estimate by Duke of a potential impact does not rise to the level of a governmental action requiring major expenditures." CUCA further averred that, until a significant cost reduction is realized or a major expenditure is required, deferral is neither appropriate nor lawful.

Additionally, CUCA opined that, if Duke seeks to defer annual estimated costs, perhaps the time has come to initiate a proceeding to estimate and then defer any expected savings and revenue windfalls Duke may enjoy as a result of governmental action during the rate freeze period, including but not limited to tax legislation.

The Attorney General commented that Duke's motion for reconsideration should be denied because it does not present sufficient new information to justify reconsideration. The Attorney General stated that the Commission had properly considered the cumulative and forward-requirements impact of SFAS 143.

The Attorney General commented that SFAS 143 was adopted in 2001. The Attorney General stated that, in addition to requiring new ARO expense guidelines for Duke's financial reporting from January 1, 2003, forward, it also required Duke to make adjustments to its ARO expenses back to day one of each nuclear plant's service. Thus, according to the Attorney General, there is a logical division between applications of the new rule based first on its present cumulative effect and second on its forward effect. Additionally, according to the Attorney General, there is greater uncertainty associated with projections of the costs to be deferred related to the forward-requirements impact than there is with respect to the determination of costs to be deferred related to the cumulative impact. The Attorney General averred that, unless Duke provides the Commission with a reliable projection of its decommissioning receipts and earnings for 2003 forward, it will be impossible for the Commission to fashion relief that maintains the status quo in consideration of the forward-requirements of SFAS 143.

The Attorney General argued that:

> The Commission's decision to make a separate determination of deferred costs for SFAS 143's cumulative and forward-requirements effects was well founded. In addition, based on its expertise in such matters, the Commission is afforded wide discretion in assessing the facts and making this policy judgment. *See State ex rel. Utils. Comm'n v. North Carolina Textile Mfrs. Ass'n,* 59 N.C. App. 240, 245, 296 S.E.2d 487, 492 (1982), rev'd on other grounds, 309 N.C. 238, 306 S.E.2d 113 (1983).

The Attorney General commented that, in its motion, Duke asked the Commission to approve the deferral of that portion of the SFAS 143 expenses which exceed the projected receipts and earnings of Duke's decommissioning fund. The Attorney General noted that the main expense under SFAS 143 will be the annual increase in the present value of the projected amount required for decommissioning. According to the Attorney General, that increase in present value is based on a discount rate, an annual percentage that reflects the estimated increase in the cost of retiring the asset as the retirement date gets closer.

The Attorney General stated that Duke's Attachment A is a comparison of projected ARO cost under SFAS 143 with projected receipts and earnings under Duke's present method of recovering decommissioning costs. The Attorney General noted that, in Attachment A, Duke does not state the length of plant service nor the discount rate applied in computing the projected ARO costs from 2003 through 2007. The Attorney General further stated that, however, Duke's estimate of earnings on its decommissioning receipts is based on actual earnings during the period 1998 through 2002.

The Attorney General argued that, in order to accurately compare SFAS 143 expenses to decommissioning receipts, the methodology of computing those two numbers should be consistent. The Attorney General stated that the annual SFAS 143 expense is based on a cost estimate, applying an appropriate discount rate over an extended time period. Similarly, according to the Attorney General, the annual trust receipts to which the expense is being compared should be based on a value estimate, applying an appropriate rate of return over the same extended time period. The Attorney General averred that Duke's Attachment A does not provide the Commission with sufficient information to determine whether Duke's methodology for comparing projected expenses and receipts is reliable.

The Attorney General stated that Duke's Attachment A does not answer the Commission's main question about deferral of SFAS 143's forward-requirements - whether SFAS 143 creates the need for major expenditures from 2003 forward. Therefore, the Attorney General argued that the Commission should not accept Duke's Attachment A as a basis for modifying the Commission's original Order. In concluding, the Attorney General moved that the Commission deny Duke's motion for reconsideration, due to the inadequacy of the additional information presented by the Company.

In its comments, the Public Staff supported Duke's request. The Public Staff restated its view, as previously stated in its initial comments, that deferral of the cumulative impact as well as the forward-requirements impact would preserve the historical and current Commission treatment of such costs for current regulatory purposes.

The Public Staff further opined that the cumulative and forward-requirements impacts of SFAS 143 are matters that are closely related and as such should be

considered collectively and not separately. The Public Staff argued that the ultimate ARO liability is unaffected by the adoption of SFAS 143 and that the interim expense increases – or deferred costs – arising from its adoption will eventually be offset by expense decreases – or deferred credits - which, ultimately, will be incorporated into the forward-requirements impact. Therefore, according to the Public Staff, deferral of the forward-requirements impact will, in effect, itself function to "amortize" the deferred cumulative impact of SFAS 143. Also, the Public Staff stated that, if the Commission does not approve the deferral of the forward-requirements impact, it will be unresolved as to how the deferred cumulative impact will be amortized.

Additionally, the Public Staff recommended that the Commission confirm that it did not intend to modify the prospective accounting for cost of removal obligations associated with assets that are not legal AROs. As the Public Staff noted, historically, cost of removal has been a component of Duke's depreciation rates as approved by this Commission. Consequently, such costs are being accrued and recognized as operating revenue deductions over the life of the related assets, rather than being charged to expense when actually paid. It is the Public Staff's position that any changes in the regulatory accounting for cost of plant removal should be considered in a general rate case or other appropriate proceeding.

CONCLUSIONS

For reasons discussed below, the Commission is of the opinion that good cause exists to grant Duke's motion for reconsideration and approve its request to defer the forward-requirements impact of SFAS 143.

As noted above, the Commission in its Order of April 4, 2003, denied the Company's initial request for deferral of the forward-requirements impact of SFAS 143. In so doing, the Commission stated that "[i]t simply cannot be determined from the record, as it presently exists, that the forward-requirements represent major expenditures or that they otherwise satisfy a condition of the Clean Smokestacks Bill [Bill] such that the Commission would have the authority to allow deferral of those costs as an exception to the rate freeze." The Bill, in particular G.S. 62-133.6(e), provides that during the rate freeze period, which began with the effective date of this provision of the Bill - June 20, 2002 - and ends December 31, 2007, the Commission may allow the deferral of costs or revenues by a utility if the utility experiences "governmental action resulting in significant cost reductions or requiring major expenditures including but not limited to the cost of compliance with any law, regulation, or rule for the protection of the environment or public health, other than environmental compliance costs."

As previously discussed, Duke takes the position that SFAS 143 constituted a single "governmental action." Accordingly, the Company argued that the Commission should have viewed the impacts of the cumulative requirement and the forward-requirements in totality rather than individually. Duke indicated that under that scenario it logically followed that the forward-requirements impact would have met the

deferral provisions of the Bill, since they would have served to enhance the magnitude of the cumulative impact. The Order allowed deferral of the cumulative impact of SFAS 143 because it was found to be a major expenditure as contemplated by the Bill.

The Public Staff also argued that the cumulative and forward-requirements of SFAS 143 should be considered collectively and not separately. The Public Staff stated that those impacts are closely related and that the forward-requirements impact would, effectively, operate to "amortize" the deferred cumulative impact of SFAS 143.

The Attorney General stated that the Commission's decision to make a separate determination of deferred costs for SFAS 143's cumulative and forward-requirements effects was well founded. The Attorney General argued that there is a logical division between applications of the new rule based first on its present cumulative effect and second on its forward effect.

The Commission agrees with the Attorney General that the present impacts should be considered separately, rather than collectively. While it may be reasonable to view the implementation of SFAS 143 as a single "governmental action" for the present purpose, its provisions clearly require the recognition of two different major categories of costs, cumulative costs and forward-requirements costs. Accordingly, the Commission is of the opinion, and so concludes, that the present arguments of the Company and the Public Staff are without merit.

Attachment A to the Company's motion is a schedule which presents, among other things, a calculation of the annual forward-requirements impact for each fiscal year during the five-year rate freeze period ending December 31, 2007, i.e., 2003 through 2007. That calculation includes partial offsets to depreciation and accretion expenses. Those offsets represent the levels of earnings expected to be realized on the decommissioning trust funds during the present five-year period. They are based on projected earnings rates which represent the Company's actual experience during the previous five-year period ended December 31, 2002, with respect to its nuclear decommissioning qualified and nonqualified trusts. Such rates appear to be significantly lower than the discount rate used by the Company to determine the present value of its nuclear decommissioning ARO. As pointed out by the Attorney General, such discount rate was not provided to the record. However, given the low levels of the projected earnings rates, it is entirely reasonable to infer that those rates are well below the discount rate.

The Commission agrees with the Attorney General that the computations should employ an appropriate discount rate and appropriate trust funds earnings rates. However, based on the position taken by the Attorney General in another docket (Docket No. E-2, Sub 826, Carolina Power & Light Company's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account), it would appear that the crux of the issue here is whether the discount rate and the trust funds' earnings rates should be the same, as well as the time periods. Sameness in those regards was the position taken by the Attorney General in Docket No. E-2, Sub 826.

The Commission disagrees with the Attorney General that the discount rate, the trust funds' earnings rates, and the time periods must be the same for the present purpose. As the Commission understands it, absent a Commission Order to the contrary, under SFAS 143, for both accounting and reporting purposes, the Company is required to recognize, on a current basis, the earnings actually realized on the trust funds. Indeed, one of the major, if not the major, differences between the periodic levels of decommissioning costs determined under the Commission's historical approach and that determined under SFAS 143 arises from the fact that the former approach is based on a levelized or uniform earnings rate over the service lives of the nuclear plants through decommissioning, whereas the latter methodology, effectively, produces variable rates. That results because the rates, in part, are functions of periodic earnings actually realized on the trust funds, which vary over time. As indicated, that is not the case with the Commission's historical approach.

Accordingly, the Commission is of the opinion, and so concludes, that, for the present purpose, it is entirely appropriate, in estimating the forward-requirements impact of SFAS 143, to use the levels of earnings the Company can reasonably be expected to achieve during the period 2003 through 2007. Further, based on the information of record, the Commission is of the opinion, and so concludes, that the estimated earnings rates employed by Duke in determining the annual levels of earnings it expects to actually realize on the trust funds during the aforesaid period are reasonable.

As previously stated, CUCA opined that a "mere expectation or estimate by Duke of a potential impact does not rise to the level of a governmental action requiring major expenditures." CUCA further averred that, until a significant cost reduction is realized or a major expenditure is required, deferral is neither appropriate nor lawful.

The Commission disagrees with CUCA. Duke's implementation of SFAS 143 with respect to the forward-requirements impact, which would be mandatory under GAAP, absent an Order from the Commission to the contrary, would require the Company to record the forward-requirements impact as an item of expense in its books, and reflect the effect of such expense in its financial reports, when incurred. Under SFAS 143, such costs are considered to be incurred by Duke beginning on January 1, 2003, notwithstanding the fact that the accrual of same requires the use of estimates. Clearly, the use of reasonable and appropriate estimates as well as reasonable and appropriate assumptions and judgment is inherent in the application of GAAP.

Whether the costs in question were precipitated by a governmental action does not appear to be in dispute. In any event, that matter was addressed by the Commission in its Order issued on April 4, 2003, in this docket, and need not be revisited here. Suffice it to say that the Commission has previously concluded that the required implementation of SFAS 143 is, effectively, a governmental action.

CUCA also commented that, if Duke seeks to defer annual estimated costs, perhaps the time has come to initiate a proceeding to estimate and then defer any expected savings and revenue windfall Duke may enjoy as a result of governmental action during the rate freeze period, including but not limited to tax legislation. However, CUCA did not point to any specific governmental action that might warrant the action suggested. Therefore, due to lack of specificity, the Commission is of the opinion, and so concludes, that CUCA's argument is without merit.

Regarding whether the present costs constitute a major expenditure as envisioned by the Bill, the Commission is of the opinion, and so concludes, that they do. In Attachment A to Duke's motion for reconsideration, the Company estimated the extent to which its total company forward-requirements costs under SFAS 143 will exceed the levels of costs currently projected. For the period 2003 through 2007, such costs, as shown in Attachment A, in the aggregate clearly constitute a major expenditure. Thus, based on that consideration and all other information of record, the Commission concludes that the forward-requirements costs collectively constitute a major expenditure as contemplated by the Bill.

Therefore, having concluded (1) that the estimated earnings rates employed by Duke in determining the annual levels of earnings it expects to actually realize on the nuclear decommissioning trust funds during the aforesaid period are reasonable and appropriate for use in the present regard, (2) that the forward-requirements costs will, in fact, be incurred and recorded as an item of expense in Duke's books, absent deferral, and (3) that the imposition of such costs results from governmental action and, absent deferral, would collectively constitute a major expenditure under the Bill, and in consideration of (4) the Public Staff's position that Duke's requests should be approved and (5) all other information of record, the Commission is of the opinion, and so concludes, that it should reconsider that portion of the Order issued April 4, 2003, in this docket, which denied Duke's request to defer the forward-requirements impact of SFAS 143 and, instead, grant such request.

There is one final matter that needs to be addressed. As previously mentioned, Duke commented that disallowance of deferral accounting for the forward-requirements impact of SFAS 143 may result in accounting changes for nonlegal asset retirement obligations that are currently being accounted for through Commission-approved depreciation rates.

The Public Staff also observed that, historically, cost of removal has been a component of Duke's depreciation rates as approved by this Commission. And, as noted above, the Public Staff recommended that the Commission confirm that it did not intend to modify the prospective accounting for cost of removal obligations associated with assets that are not legal AROs.

Depreciation expense, which in part is a function of depreciation rates, was included as a component of the Company's North Carolina retail (N.C. retail) cost of service established in the context of the Company's last general rate case proceeding.

Consequently, the recovery of that expense, which includes the cost of removal, is now provided for in the rates and charges Duke is authorized to charge for its sales of service with respect to its N.C. retail operations. Consistent with the economic consequences of that regulatory treatment, the cost of removal is accrued and recognized as an operating revenue deduction over the useful life of the related assets, rather than waiting to record the expense until the assets are actually removed and the related costs actually paid. It is the Public Staff's position that any changes in accounting for those costs should be considered in a general rate case or other appropriate proceeding.

In consideration of the fact that recovery of the cost of removal in question has been and is now provided for in the Company's rates, as approved in the context of its last general rate case proceeding as well as other past proceedings, and in consideration of the magnitude of such costs, the Commission is of the opinion, and so concludes, that, as suggested by the Public Staff, it is entirely appropriate, to avoid any misconstruction, for the Commission to confirm that it did not intend to, and did not, prospectively or otherwise, modify the regulatory treatment previously adopted for the cost of removal as provided for most recently in the context of the Company's last general rate case proceeding. Additionally, the Commission is of the opinion, and so concludes, that the Company should be, and hereby is, explicitly placed on notice that any proposed changes in the cost of removal for long-lived assets and/or in the accounting for such costs must be submitted to the Commission for its approval in the context of a general rate case or other appropriate proceeding prior to implementation.

IT IS, THEREFORE, ORDERED as follows:

1. That Duke's motion requesting that the Commission reconsider that portion of its Order issued April 4, 2003, in this docket, which denied the Company's request to defer the forward-requirements impact of the FASB's SFAS 143, shall be, and hereby is, allowed.

2. That, on reconsideration, Duke's request to defer the forward-requirements impact of SFAS 143 shall be, and hereby is, approved subject to the following conditions, to the end that Duke's adoption of SFAS 143 shall, in effect, have no impact, currently or prospectively, on the Company's North Carolina retail operations, pending further order of the Commission:

a. That the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs.

b. That the adoption of SFAS 143 shall have no impact on Duke's operating results or return on rate base for North Carolina retail regulatory purposes and that the net effect of the deferral accounting allowed shall be to reset Duke's North Carolina retail rate base, net

operating income, and regulatory return on common equity to the same levels as would have existed had SFAS 143 not been implemented.

c. That the implementation of SFAS 143 for financial reporting purposes and the deferrals allowed in this docket shall have no impact on the ultimate amount of costs recovered from the North Carolina retail ratepayers for nuclear decommissioning or other AROs, subject to future orders of the Commission.

d. That the individual line items and account balances in the quarterly ES-1 surveillance filings and the annual cost of service studies filed by Duke with the Commission shall be stated as if SFAS 143 had not been implemented by Duke.

e. That when Duke files its annual report required by Commission Rule R1-32, it shall also file a reconciliation of the account balances set forth in that report (both total company and North Carolina) with the account balances set forth in the annual cost of service studies filed with the Commission.

f. That no portion of the total ARO asset or liability shall be included in rate base for North Carolina retail accounting or ratemaking purposes.

g. That no portion of the total ARO asset or liability shall be included in the Construction Work in Progress base to which Duke applies its AFUDC [Allowance for Funds Used During Construction] rate.

h. That neither the depreciation rates utilized by Duke nor the depreciable bases to which it applies those rates shall be changed due to the implementation of SFAS 143.

i. That Duke shall file with the Commission the journal entries setting forth the initial implementation of SFAS 143 and all other entries related to SFAS 143 for calendar year 2003, as well as all entries implementing the deferrals allowed by the Commission's Orders.

j. That all entries made and amounts recorded as a result of the implementation of SFAS 143 and the deferrals allowed by the Commission's Orders shall be subject to ongoing review by the Commission, the Public Staff, and other parties to this docket.

k. That the deferral accounting treatments allowed by the Commission's Orders shall not prejudice any party from taking issue with the amount or the treatment of any deferral of ARO costs in a rate or other appropriate proceeding, including a proceeding initiated in

Docket No. E-100, Sub 56 for the purpose of determining nuclear decommissioning expenses.

3. That the Commission, in its Order issued April 4, 2003, in this docket, did not intend to, and did not, modify the regulatory treatment previously established for cost of removal obligations associated with assets that are not legal AROs.

4. That, absent an explicit Commission order to the contrary, Duke shall continue to accrue cost of removal obligations associated with assets that are not legal AROs through its depreciation rates as prescribed most recently in the Commission Order ruling on the Company's application for a general rate increase in Docket No. E-7, Sub 487.

5. That Duke shall submit all proposed changes in the cost of removal for all long-lived assets and/or in the accounting for such costs, if any, to the Commission for its approval prior to implementation. Such changes, when submitted, shall be considered in the context of a general rate case or other appropriate proceeding.

6. That, except as modified herein, the Commission Order issued April 4, 2003, in this docket, shall remain in full force and effect.

ISSUED BY ORDER OF THE COMMISSION.

This the 8th day of August, 2003.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk

Chairman Jo Anne Sanford and Commissioner Lorinzo L. Joyner did not participate.

DH080703.01

AGO McManeus/Speros Cross Ex. 3
Docket No. E-7, Sub 1214A

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH
Docket No. E-2, Sub 1103
Docket No. E-7, Sub 1110

In the Matter of	)	
Joint Petition of Duke Energy Progress, LLC	)	COMMENTS
and Duke Energy Carolinas, LLC for an	)	OF THE
Accounting Order to Defer Environmental	)	ATTORNEY GENERAL'S
Compliance Costs	)	OFFICE

The North Carolina Attorney General's Office ("AGO") respectfully submits these comments regarding the joint petition ("Joint Petition") of Duke Energy Progress, LLC ("Duke Progress") and Duke Energy Carolinas, LLC ("Duke Carolinas") (collectively, "Duke Energy") requesting issuance by the Commission of "an accounting order for regulatory accounting purposes authorizing [Duke Energy] to defer in a regulatory asset account (until [Duke Energy's] next base rate cases) certain costs incurred in connection with compliance with federal and state environmental requirements as it relates to Coal Combustion Residuals ("CCRs" or "coal ash")."[1]

Introduction

The coal ash costs that Duke Energy seeks to recover are out-of-the-ordinary and very concerning because they may result in large rate increases for consumers. There are important questions that need to be addressed regarding whether all of the costs that Duke Energy seeks to recover were reasonably and prudentially incurred. It would not be appropriate to make important, binding, substantive determinations regarding recovery of these costs in a procedural,

[1] Joint Pet. at 1.

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accounting-related docket. The Commission should ensure that all of the issues regarding coal ash cost recovery will not be resolved or prejudged until there is a complete evidentiary record in the upcoming rate cases. The Commission should direct Duke Energy to record the costs temporarily in the FERC USOA balance sheet asset account entitled Account 186 – Miscellaneous Deferred Debits, or another appropriate account, and to state that the authorization for temporary deferral pending a hearing on the merits does not provide any presumptions in favor of Duke Energy. [2] This will provide all parties to the proceeding with an opportunity to make all legal and substantive arguments during the rate case and its accompanying evidentiary proceedings. It would not be in the public interest for recovery issues to be decided prematurely prior to the rate case.

Factual Background

On 22 December 2008, the failure of a dike that was used to contain coal ash at a Tennessee Valley Authority plant resulted in 5.4 million cubic yards of coal ash waste being released into the Emory River.[3] In 2009, the EPA released its list of forty-four coal-fired power plant waste sites with "high hazard potential."[4]

[2] This approach was used by the Commission in Order Denying Request to Implement Rate Rider and Scheduling Hearing to Consider Request for Creation of Regulatory Asset Account, In the Matter of Duke Energy Carolinas, LLC for Approval of Rate Rider to Allow Prompt Recovery of Costs Related to Purchases of Capacity Due to Drought Conditions in Docket No. E-7, Sub 849, issued 2 June 2008 ("2008 Duke Carolinas Drought Accounting Order Request") at 23.
[3] *See, e.g.*, U.S. Environmental Protection Agency and Tennessee Valley Authority Kingston Coal Ash Release Site Project Completion Fact Sheet, December 2014, https://www.epa.gov/sites/production/files/2016-02/documents/projectcloseout_dec2014_factsheet.pdf.
[4] *See, e.g.*, *EPA list shows dangerous coal ash sites found in 10 states*, June 29, 2009, McClatchy, available at http://www.mcclatchydc.com/news/nation-world/national/article24543913.html.

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Twelve of these sites were in North Carolina; ten were operated by Duke Energy Carolinas and two by Progress Energy Carolinas.[5]

On 21 June 2010, the EPA solicited comments on the regulation of coal ash, laying out two possible regulatory scenarios.[6] Both involved requiring liners for coal ash ponds and groundwater monitoring; one also required closure of coal ash ponds.[7] On 2 February 2014, as a result of the failure of Duke Carolinas to properly maintain and inspect two stormwater pipes running underneath the primary coal ash basin at its Dan River Steam Station in Eden, a pipe failed and resulted in the discharge of approximately 27 million gallons of coal ash wastewater and between 30,000 and 39,000 tons of coal ash into the Dan River.[8] Duke Carolinas, Duke Progress, and Duke Energy Business Services were charged with criminal violations of federal environmental laws, and on 14 May 2015 they pled guilty to nine counts, involving unlawful discharges and/or failures to maintain coal ash impoundments at H.F. Lee Steam Electric Plant, Cape Fear Steam Electric Plant, Asheville Steam Electric Plant, Riverbend Steam Station, and Dan River Steam Station.[9]

Following the Dan River spill, the North Carolina General Assembly passed the Coal Ash Management Act of 2014, which, among other things,

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[5] *Id.*
[6] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric Utilities, Part II, 80 FR 21302, 21303 (Apr. 17, 2015).
[7] *Id*.
[8] *United States v. Duke Energy Business Services, LLC et al*., Joint Factual Statement ¶ 1 (5:15 CR 2, 5:15 CR 67, 5:15 CR 68, May 14, 2015).
[9] *United States v. Duke Energy Business Services, LLC et al.,* Plea to Criminal Information and Sentencing Hearing Before Judge Malcolm J. Howard, 5:15-cr-00067-H, doc. 68; Joint Factual Statement, doc. 67 (May 14, 2015).

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required closure of coal ash ponds in North Carolina.[10] The EPA published its final coal ash regulations on 17 April 2015, with an effective date of 14 October 2015.[11]

On 7 November 2014 Duke Energy Corporation filed its Form 10-Q for the quarter ending 30 September 2014, recording an asset retirement obligation ("ARO") of $3.423 billion "based upon the legal obligation for closure of coal ash basins and the disposal or related ash as a result of the Coal Ash Act and the agreement with [the South Carolina Department of Health and Environmental Control]."[12] Shortly thereafter, Duke Energy began incurring the expenses for which it now seeks deferred regulatory accounting treatment: "Expenses incurred for state and federal compliance and requested for deferral (January 2015 – November 2016) include $434.4 million for [Duke Carolinas] and $291.9 million for [Duke Progress]."[13]

Duke Energy has recorded Asset Retirement Obligations ("AROs") on its Condensed Consolidated Balance Sheets as of September 30, 2016 in the amount of $4.5 billion, based on the estimated legal obligation for closure of coal ash basins and the disposal of related coal ash to comply with state and federal environmental requirements;[14] however, Duke Energy states that total actual compliance costs incurred could be materially different from these estimates.[15]

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[10] North Carolina General Assembly S.B. 729, Part II (Aug. 20, 2014).
[11] 80 FR 21302, 21302.
[12] Duke Energy, Quarterly Report (Form 10-Q) at 56, 50 (Nov. 7, 2014).
[13] Joint Pet. at 2.
[14] Joint Pet. at 4-5.
[15] *Id*. at 9.

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Procedural History

On 21 December 2015, Duke Energy sent a letter to the Commission, called "Explanation of Accounting Treatment Related to Coal Ash Basin Obligations."[16] In the letter, Duke Energy informed the Commission that it had accounted for its ongoing and expected coal ash expenses by recording an ARO, as required by GAAP and Federal Energy Regulatory Commission Uniform System of Accounts and General Instruction No. 25.[17] It further informed the Commission that it had created a regulatory asset account.[18] Specifically, Duke Energy asserted that "[t]he Commission has issued orders allowing the companies to defer all impacts of establishing an ARO until these costs can be considered in future ratemaking decisions."[19] Duke Energy noted that in addition to accounting for its coal ash-related ARO as required by GAAP, it was also "recording a debt and equity return ('carrying charge') on the [ARO] net asset for regulatory purposes."[20] It is currently deferring the equity portion of the carrying charge "until rate recovery has begun" but had already recorded approximately $2.7 million as "the debt return" through November 30, 2015.[21]

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[16] Joint Pet., Ex. 1.
[17] *Id*. at 1.
[18] *Id*. at 6.
[19] *Id*. at 2, citing Order Granting Motion for Reconsideration and Allowing Deferral of Costs In the Matter of Duke Power's Petition for Authority to Place Certain Asset Retirement Obligation Costs In a Deferred Account, Docket No. E-7, Sub 723 (August 8, 2003) ("2003 Duke Power Order") at 11; and the Order Granting Motion for Reconsideration and Allowing Deferral of Costs In the Matter of Carolina Power & Light Company's Petition for Authority to Place Certain Asset Retirement Obligation Costs in a Deferred Account, Docket No. E-2, Sub 826 (August 12, 2003) ("2003 Duke Carolinas Order") at 11 (collectively the "2003 Orders").
[20] *Id*. at 7.
[21] *Id*. at 8.

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Duke Energy stated that authority to defer the costs was not being requested "at that time due to significant litigation and reconsiderations related to CAMA, the now-defunct Coal Ash Management Commission, and numerous other outstanding issues."[22]

On 28 March 2016, the Commission issued an Order Acknowledging Receipt of Filing and created formal dockets related to the establishment of AROs and attendant regulatory assets associated with coal ash costs. The Commission noted that it was not taking any action to address the accounting method announced by Duke Energy, because Duke Energy had not requested any Commission action.[23] The Commission stated that its order "should not be construed as agreement or disagreement with the substance of Duke's analysis or the conclusions Duke reaches."[24]

On 30 December 2016, Duke Energy filed the Joint Petition. In the Joint Petition, Duke Energy requests Commission approval to use Account 182.3 to defer the actual costs incurred,[25] specifically, "to defer to a regulatory asset, until the effective date of new rates from the next base rate case, all non-capital costs as well as the depreciation expense and cost of capital at the weighted average cost of capital for all capital costs" related to activities required to comply with the federal and state regulations.[26] In addition, Duke Energy requests approval to

[22] *Id.* at 10-11.
[23] Order Acknowledging Receipt of Filing at 1.
[24] *Id*. at 1-2.
[25] Joint Pet. at 13.
[26] *Id*. at 14.

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defer a cost of capital on the deferred costs at the weighted average cost of capital.[27]

Duke Energy informed the Commission that it intends to file general rate cases within twelve months of the filing date of the Joint Petition in order to address the prudency and ratemaking effects of the costs.[28]

Analysis

I. The Significant Factual Issues Raised by the Joint Petition Should Be the Subject of an Evidentiary Hearing.

The North Carolina Public Utilities Act provides that all rates by public utilities "shall be just and reasonable." N.C. Gen. Stat. 62-131(a). Moreover, all rates must be fair to the consumer. "[T]he Commission shall fix such rates as shall be fair both to the public utilities and to the consumer." N.C. Gen. Stat. 62-133(a).

There are a number of significant factual issues posed by Duke's request for cost deferral that require an evidentiary hearing for valid determination. North Carolina law provides that "[t]he Commission shall render its decisions upon questions of law and of fact in the same manner as a court of record."[29] Because of the number and complexity of the issues posed by the Joint Petition, it is appropriate for the Commission to allow Duke Energy to temporarily record its coal ash costs in the FERC USOA balance sheet asset account 186 (Miscellaneous Deferred Debits) or another appropriate temporary deferral account pending a hearing and final Commission determination as was ordered

[27] *Id*.
[28] *Id.* at 13.
[29] N.C. Gen. Stat. § 62-60 (2016).

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in the 2008 Duke Carolinas Drought Accounting Order Request.[30] Here, as then, "an evidentiary hearing is equitable, appropriate, and necessary" to resolve the questions of whether a request to create a regulatory asset is appropriate legally and as a matter of regulatory policy.[31]

The costs at issue are large, complex, and out-of-the-ordinary and need to be determined in a docket where there is sufficient transparency, where the parties have sufficient time to analyze the details of the costs for which Duke Energy seeks to recover and to conduct full and appropriate discovery, and where Duke Energy provides sufficient details on the record for the Commission to make a thorough and appropriate determination regarding the issue. The burden is on Duke Energy when it seeks recovery of such costs, and the Commission needs to give full consideration to the issue in order to protect the public interest.

II. The Commission Should Not Prematurely Reach Decisions on Substantive Cost Recovery Issues.

In two orders entered in 2003, the Commission stated that the predecessors to Duke Progress and Duke Carolinas should seek approval of the Commission prior to changing the accounting for the costs of removal of long term assets (*e.g.*, such as the costs of closing coal ash basins).[32] The 2003 Orders addressed an issue created by a new rule, SFAS 143, adopted by the Financial Accounting Standards Board ("FASB"), which required Progress

[30] 2008 Duke Carolinas Drought Accounting Order Request at 20.
[31] *Id*.
[32] *See* 2003 Duke Carolinas Order at 13; 2003 Duke Progress Order at 13-14 (emphasis added); *See* Joint Pet. Ex. 1 at 2 and fn 1 therein citing the 2003 Orders. SFAS 143 is now known as ASC 410-20, the same accounting rule in play in this matter. *See* Joint Pet. Ex. 1 at 5.

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Energy Carolinas and Duke Power to change the way certain AROs were accounted for under GAAP.[33] FASB had recognized that GAAP accounting and regulatory accounting could differ for AROs, and accordingly authorized utilities to recognize a regulatory asset or liability for the difference between the two accounting approaches.[34] The two companies had filed their petitions seeking permission to do just that, create a regulatory deferred account so that they could "place all income statement impacts arising from the … adoption of [the new GAAP rule] in regulatory deferred accounts." [35]

The Commission granted permission to create the regulatory deferred account subject to certain express conditions, including that 1) "the intent and outcome of the deferral process [approved for asset retirement obligation accounting] shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs," and 2) the utility "shall submit all proposed changes in the cost of removal for all long-lived assets and/or in the accounting for such costs, if any, to the Commission for its approval prior to implementation. Such changes, when submitted, shall be considered in the context of a general rate case or other appropriate proceeding."[36] The Commission specifically recognized that the cost of removal of assets had been a component of the depreciation rates for both Duke Carolinas and Duke Progress, that costs were being accrued in rates over the useful life of the related assets, and that the treatment of depreciation was

[33] 2003 Duke Carolinas Order at 1; 2003 Duke Progress Order at 1.
[34] *Id*.
[35] 2003 Duke Carolinas Order at 2; 2003 Duke Progress Order at 2.
[36] *See* 2003 Duke Carolinas Order at 13; 2003 Duke Progress Order at 13-14 (emphasis added).

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not to be changed by the implementation of SFAS 143.[37] The Commission drew a clear line between what was required for GAAP accounting and what the Commission required: "the intent and outcome of the deferral process shall be to continue the Commission's currently existing accounting and ratemaking practices for nuclear decommissioning costs and other ARO costs."[38]

On 28 March 2016, several months after Duke Energy filed the 21 December 2015 letter, the Commission issued an Order in which it acknowledged the receipt of the letter and created formal dockets related to the establishment of AROs and attendant regulatory assets associated with coal ash costs. As noted above, the Commission did not take any action to address the accounting changes announced by Duke Energy, observing that Duke Energy had not requested any Commission action. The Commission stated that its action "should not be construed as agreement or disagreement with the substance of Duke Energy's analysis or the conclusions Duke reaches."

III. Any Order Granting Duke Energy's Joint Petition In Whole or In Part, Should Be Without Prejudice to Any Party's Right To Contest In Future Ratemaking Proceedings the Appropriateness of Recovery of Coal Ash-Related Costs to Ratepayers.

Duke Energy acknowledges that it would be appropriate for the Commission to review its coal ash costs "in broad scope" in a future setting, such

[37] 2003 Duke Carolinas Order at 10-12; 2003 Duke Progress Order at 11-12. This is one of the factors that distinguishes the Joint Petition from Piedmont Natural Gas's application for deferred accounting on which Duke Energy relies. Joint Pet. at 14. In the case of Piedmont's expenses for addressing new US Department of Transportation regulations, the costs were "entirely distinct and different in nature from its historical [operations and maintenance] expenses. In the Matter of Application of Piedmont Natural Gas Company, Inc. for Approval of Deferred Accounting Treatment of Interim Pipeline Integrity Management Regulation Compliance Costs Dockets G-9, Sub 495 and G-21, Sub 457, Order Approving Deferred Accounting Treatment at 1 (2 December 2004). In addition, Piedmont requested the deferred accounting prior to incurring expenses. *Id*.

[38] 2003 Duke Carolinas Order at 12-13; 2003 Duke Progress Order at 12.

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as a rate proceeding.[39] The AGO does not oppose postponing this inquiry to a future ratemaking case, and submits that—without limitation—the factors set out below are among those that should be preserved for future review and consideration:

Reasonableness and prudence. Among other factors, it is pertinent for the Commission to assess whether the construction, operation and management of Duke Energy's coal ash sites have been reasonable and prudent, as well as whether the clean-up costs were reasonably and prudently incurred.[40] Duke Energy also asks for this issue to be preserved for consideration in future proceedings.[41]

In addition, Duke Energy's deferral request seeks full recovery of coal ash costs from ratepayers.[42] However, the Commission has previously concluded that in some instances it is not appropriate for ratepayers to relieve shareholders of all responsibility for the environmental clean-up of utility sites by transferring such costs to current ratepayers.[43] In the context of deferred accounting requests, this Commission has stated that the full amount of major unexpected expenditures should not fall on ratepayers alone, but that there should be a fair division of such costs between ratepayers and shareholders, taking into account,

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[39] Joint Pet. at 1.
[40] The Commission describes these same factors in its discussion of cost recovery for environmental costs associated with manufactured gas plants in the Order Granting Partial Rate Increase *In the Matter of Application of Public Service Company of North Carolina, Inc., for an Adjustment of its Rates and Charges* issued 7 October 1994 in Docket No. G-5, Sub 327 ("1994 PSNC Rate Case") at 22.
[41] *See* Joint Pet. at 1.
[42] Joint Pet. at 2.
[43] 1994 PSNC Rate Case at 23.

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among other things, whether the utility has achieved a reasonable level of earnings during the period for which it seeks deferred accounting.[44]

Legal prohibitions on recovery. Duke Energy states that it does not seek deferral of any costs associated with the Dan River pipe break repair and spill cleanup, and nor will it seek recovery of such costs in future rate recovery.[45] Under North Carolina law, "[t]he Commission shall not allow an electric public utility to recover from the retail electric customers of the State costs resulting from an unlawful discharge to the service waters of the State from a coal combustion residuals surface impoundment."[46] Under its plea agreements, Duke Energy cannot seek a rate increase based on compliance with the criminal fines, restitution related to the counts of conviction, community service payments, its mitigation obligations under the plea agreement, the costs of the Dan River clean up, and/or the funding of the environmental compliance plans required under its plea agreements.[47] The accounting details are important in this context and, accordingly, whether and the extent to which these types of costs are included in Duke Energy's request for recovery should be examined in the context of a developed evidentiary record.

Recovery of carrying costs. Whether Duke Energy may recover carrying costs (*e.g.*, in the event coal ash costs are amortized, whether it is appropriate for Duke Energy to earn a rate of return on the unamortized balance) is an issue

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[44] 2008 Duke Carolinas Drought Accounting Order Request at 10.
[45] Joint Pet. at 2.
[46] N.C. Gen. Stat. § 62-133.13.
[47] *United States v. Duke Energy Business Services, LLC et al.,* Plea to Criminal Information and Sentencing Hearing Before Judge Malcolm J. Howard, 5:15-cr-00067-H, doc. 68 at 38 (May 14 2015).

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that may be contested in the rate proceedings. The Commission has previously disallowed the recovery of carrying costs associated with the clean-up of manufactured gas plants.[48] Here, it is appropriate for the Commission to consider what rate of return Duke Energy should receive in light of the nature of the costs Duke Energy seeks to recover.

Propriety of recovery in light of cost recovery through depreciation or other methods. Duke Energy notes that the current rates for Duke Progress include a component for coal ash remediation costs as part of the Cost of Removal included in depreciation rates but does not explain in detail how Duke Carolinas has addressed such costs for recovery over the useful life of the assets.[49] One of the factors that may be contested is the extent to which Duke Energy has already collected some coal ash costs through past rates.

Appropriate contribution from insurance proceeds or responsible third parties. Another factor that Duke Energy may need to address is whether insurance or third party sources are or may be responsible to fund or contribute to coal-ash related costs.

Conclusion

The Commission should ensure that all of the substantial issues regarding cost recovery will not be resolved or prejudged until there is a complete evidentiary record in the upcoming rate cases. The Commission should direct Duke Energy to set up a temporary regulatory asset on its books so that all of the factual and legal issues raised by the Joint Petition can be fully reviewed on an

[48] *See* 1994 PSNC Rate Case at 23.
[49] Joint Pet. at 5.

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evidentiary record and without prejudice to the ability of any party to raise other cost recovery related issues at the rate case.

Respectfully submitted, this the 15th of March, 2017.

JOSH STEIN
Attorney General

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CERTIFICATE OF SERVICE

The undersigned certifies that she has served a copy of the foregoing INITIAL COMMENTS OF THE ATTORNEY GENERAL'S OFFICE upon the parties of record in this proceeding by electronic mail.

This the 15th day of March, 2017.

/s/ Margaret A. Force
Margaret A. Force
Assistant Attorney General

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April 19, 2017

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

RE: In the Matter of Joint Petition of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, for an Accounting Order to Defer Environmental Compliance Costs
Docket No. E-2, Sub 1103
Docket No. E-7, Sub 1110

Dear Ms. Jarvis:

Pursuant to the Order Granting Extension of Time to File Reply Comments entered April 7, 2017, please find enclosed for filing in the above-referenced Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Reply Comments in Support of its Joint Petition for an Accounting Order to Defer Environmental Compliance Costs.

If you have any questions, please let me know.

Sincerely,

/s/ Heather Shirley Smith

Heather Shirley Smith

HSS/ksh

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STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. E-2, SUB 1103
DOCKET NO. E-7, SUB 1110

In the Matter of Joint Petition of Duke Energy Progress, LLC, and Duke Energy Carolinas, LLC, for an Accounting Order to Defer Environmental Compliance Costs	)))))	**DUKE ENERGY PROGRESS, LLC AND DUKE ENERGY CAROLINAS, LLC'S REPLY COMMENTS IN SUPPORT OF ITS JOINT PETITION FOR AN ACCOUNTING ORDER TO DEFER ENVIRONMENTAL COMPLIANCE COSTS**

NOW COMES Duke Energy Progress, LLC ("DEP") and Duke Energy Carolinas, LLC ("DEC") (collectively the "Companies"), by and through counsel, pursuant to the North Carolina Utilities Commission's ("Commission") January 6, 2017 *Order Requesting Comments* and its March 9, 2017 *Order Granting Additional Extensions of Time to File Comments*, and respectfully submits their Reply Comments in support of the Companies' Joint Petition for an Accounting Order to Defer Environmental Compliance Costs. With these Reply Comments, the Companies respectfully reaffirm their respective requests that the Commission issue an order authorizing the Companies to defer certain regulatory compliance obligations as a regulatory asset in Account 182.3—Other Regulatory Assets, pending Commission review of the reasonableness and prudence of these costs in future general rate case proceedings to be filed later this year. In support of these Reply Comments, the Companies respectfully submit to the Commission the following:

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RELEVANT BACKGROUND

1. On December 30, 2016, the Companies jointly filed a Petition for an Accounting Order ("Petition") in the above-captioned dockets requesting that the Commission issue an Order authorizing the Companies to defer in a regulatory asset account certain costs of compliance with federal and state environmental requirements regarding coal combustion residuals ("CCRs"). In the Petition, the Companies described their ongoing efforts to comply with new environmental requirements related to the Environmental Protection Agency's ("EPA") final rule[1] ("CCR Rule") and the North Carolina Coal Ash Management Act ("CAMA"). The Petition detailed the significant projected costs to comply with the CCR Rule and CAMA and, relatedly, the significant projected financial impact to the Companies in light of these new and extraordinary regulatory obligations. The Companies also noted that they each intend to file a base rate case within the next 12 months.

2. On January 6, 2017, the Commission entered its *Order Requesting Comments*, permitting interested parties to submit comments regarding the Petition no later than February 15, 2017, and directing the Public Staff to file its comments no later than March 15, 2017.

3. On March 8, 2017, the Public Staff filed a motion requesting that the due dates for initial comments and reply comments be extended to March 15, 2017, and April 12, 2017, respectively. The Commission issued its *Order Granting Additional Extensions of Time to File Comments* on March 9, 2017, granting the Public Staff's request.

4. Also on March 8, 2017, NC WARN, Appalachian State University ("ASU"), and the Cities of Concord and King's Mountain ("Cities")[2] filed initial comments. The Public Staff, the Attorney General's Office (the "Attorney General"), and the Carolina Utility Customers

[1] *Hazardous and Solid Water Mgmt. System; Disposal of Coal Combustion Residuals from Elec. Utils.*, 80 FR 21301 (Apr. 17, 2015).

[2] The Cities and ASU filed separate but identical comments.

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Association, Inc. ("CUCA") filed comments on March 15, 2017. In these Reply Comments, the Companies refer to the comments filed by ASU, the Attorney General, the Cities, the CUCA, NC WARN and the Public Staff, collectively as the "Comments," and the parties to the proceeding as the "Intervenors."

5. Collectively, the Intervenors do not raise any issues that should affect the Commission's review of the Companies' accounting request. Of note, no intervenor directly asserted that the Companies' request for deferral accounting should be denied in its entirety. In fact, the Public Staff affirmatively stated that the Companies' non-capital costs and depreciation expense related to state and federal requirements meet the criteria for deferral.[3] The Companies' request meets the well-established standard for granting deferral accounting authority in terms of the magnitude and extraordinary nature of the costs incurred and the resulting impact on the Companies' financial condition. Therefore, the Commission should approve the request, subject only to the condition that rate recovery issues should be decided in their upcoming general rate cases to be filed later in 2017. Because the Companies will file general rate cases within the year, it is not necessary to establish a hearing to examine the reasonableness and prudence of the costs sought to be deferred. Indeed, Intervenors' Comments predominately addressed cost recovery matters more appropriately raised in the general rate case proceedings. In addition, Intervenors request several adjustments to the Companies' proposed accounting entries. The Companies do not object to the Public Staff's request that determinations about the amortization of the deferred expenses should be delayed and decided on in the next respective general rate proceedings. However, the Intervenors' other arguments requesting more granularity in the Companies' accounting are not necessary for this proceeding.

[3] Public Staff Comments at p. 6 ("In this particular case, the Public Staff believes that the non-capital costs and depreciation expense related to compliance with state and federal requirements cited in the Companies' petition generally satisfy the criteria for deferral for regulatory accounting (but not necessarily ratemaking) purposes.").

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REPLY TO COMMENTS

A. The Petition Satisfies the Commission's Requirements for Deferral

1. The Petition Meets the Standard for Deferral

6. When considering a request for deferral, the Commission evaluates: 1) the extraordinary nature and uniqueness of the costs requested to be deferred (and the magnitude of the costs); and 2) whether, absent authorizing deferral, the costs would have a material impact on the company's financial condition.[4] When evaluating the public utility's financial condition, the Commission reviews the impact on the company's achieved level of earnings during the requested deferral period.[5] The Commission may also consider "whether the company has requested, or is contemplating requesting, a general rate increase and the timing, or the proposed timing, of the filing of such a request."[6]

7. The Companies' request meets the Commission's criteria for granting deferral. None of the Intervenors dispute the basis for the Companies' request: 1) the Federal government and State of North Carolina have adopted significant new legislation and regulatory requirements obligating the Companies to spend significant amounts to comply with the CCR Rule and CAMA;[7] and 2) denial of the request would adversely affect the Companies' financial stability.[8] As shown in the Petition (and not disputed by the Intervenors), the adverse impact to earnings, as

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[4] Public Staff Comments at pp. 4-5 (citing *In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Environmental Compliance Costs and the Incremental Costs Incurred From the Purchase of a Portion of Saluda River's Ownership in the Catawba Nuclear Station*, NCUC Docket No. E-7, Sub 874, *Order Approving Deferral Accounting with Conditions*, (Mar. 31, 2009); *In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Capital and Operating Costs Incurred for the Advanced Clean Coal Cliffside Unit 6 Steam Generating Plant, the Dan River Natural Gas Combined Cycle Generating Plant, and the Capacity-Related Modifications at the McGuire Nuclear Generating Plant*, NCUC Docket No. E-7, Sub 1029, *Order Approving in Part and Denying in Part Request for Deferral Accounting* (Apr. 3, 2013) ("*Generator Deferral Order*").

[5] *See Generator Deferral Order* at pp. 12-13.

[6] *Generator Deferral Order* at p. 10 (referencing order in NCUC Docket No. E-7, Sub 874 where the Commission found that "the financial consequences and the fact that the Company was planning to file a rate case in the near term warranted deferral").

[7] Petition at PP 5-14.

[8] Petition at PP 15-.

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calculated for the 12-month period ending September 30, 2016, was 244 basis points for DEP and 247 basis points to DEC.[9] Furthermore, the Companies reiterate their intent to file general rate cases during 2017 where all issues related to recoverability of the deferred costs will be determined. Indeed, none of the Intervenors even requests that the Commission deny the Petition in its entirety.[10] The Public Staff affirmatively states that the Companies' non-capital costs and depreciation expense related to state and federal requirements generally meet the Commission's criteria for deferral.[11] The Attorney General notes that it "is appropriate for the Commission to allow [the Companies] to temporarily record its coal ash costs" in FERC Account 186 or "another appropriate temporary deferral account pending a hearing and final Commission determination."[12] Other Intervenors only oppose the request in part by recommending that certain costs be carved out from the deferral. Such arguments should be rejected, as discussed in more detail below.

8. In short, the Companies' deferral request is appropriate based on Commission precedent, is consistent with the Commission's recent treatment of CCR-related asset retirement obligation ("ARO") costs borne by Dominion North Carolina Power ("Dominion") and authorized for deferral and recovery in that utility's 2016 general rate case,[13] and should be granted.

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[9] Petition at PP 18-19.

[10] CUCA, the Cities, and ASU, speculate as to inclusion of certain costs, issues best left to each Companies' general rate case, as discussed in more detail in PP 19-20 below.

[11] Public Staff Comments at p. 6 ("the Public Staff does not object to a deferral of these expenses for regulatory accounting purposes. . .").

[12] Attorney General's Comments at p. 7.

[13] Petition at p. 15 and n.9 (citing *In the Matter of Application of Virginia Electric & Power Company, d/b/a Dominion North Carolina Power, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, NCUC Docket No. E-22, Sub 532, *Order Approving Rate Increase and Cost Deferrals an Revising PJM Regulatory Conditions* at p. 62 (Dec. 22, 2016) ("Based upon the entire evidence of record, the present Stipulation to allow the test year CCR costs to be recovered in this case by amortization over a five-year period with the unamortized balance to earn a return and the authorization to treat future CCR costs incurred through 2018 as a regulatory asset (which is the mechanism to facilitate the deferral of future CCR costs) is proper and in the public interest under the facts and circumstances of this case.")).

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2. An Evidentiary Hearing on the Petition for Deferral is Not Necessary

9. The Attorney General states that there "are a number of significant factual issues posed by Duke's request for cost deferral that require an evidentiary hearing for a valid determination."[14] The Attorney General supports its request by referencing a different docket where the Commission ordered an evidentiary hearing to evaluate proposed regulatory asset accounting treatment.[15] NC WARN also requests that the Commission consider issues of coal ash cleanup in "a separate proceeding, rather than a rate case," and that the Commission conduct an evidentiary hearing.[16]

10. It is not necessary to establish an evidentiary hearing to examine the deferral request. While the Commission's review of CCR-related cost recovery will likely be complex, the issues underlying the deferral request are fairly simple and can be resolved on the written record. As described above, the Companies meet the criteria for deferral. The Companies are not obligated to show reasonableness and prudence of costs for the Commission to grant its requested accounting treatment.[17] Any costs deferred will be subject to evaluation of prudency and reasonableness by the Commission in the Companies' future general rate cases.

11. The Attorney General's reference to the Drought Proceeding is factually distinguishable and not relevant. DEC's primary request in that proceeding was for a cost recovery rider. With respect to the regulatory asset under consideration in the Drought

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[14] Attorney General's Comments at p. 7.

[15] Attorney General's Comments at pp. 2, 7 (citing *In the Matter of Application of Duke Energy Carolinas, LLC for Approval of Rate Rider to Allow Prompt Recovery of Costs Related to Purchases of Capacity Due to Drought Conditions*, NCUC Docket No. E-7, Sub 849, *Order Denying Request to Implement Rate Rider and Scheduling Hearing to Consider Request for Creation of Regulatory Asset Account* (June 2, 2008) ("*Drought Proceeding Order*")). This proceeding will be referred to as the "Drought Proceeding" in these Reply Comments.

[16] NC WARN Comments at p. 5.

[17] *See, e.g., In the Matter of Petition of Duke Energy Carolinas, LLC for an Accounting Order to Defer Certain Environmental Compliance Costs and Incremental Costs Incurred from the Purchase of a Portion of Saluda River's Ownership in the Catawaba Nuclear Station*, NCUC Docket No. E-7, Sub 874, *Order Approval Deferral Accounting with Conditions*, at p. 19 (Mar. 31, 2009) (Commission approving deferral without reviewing prudency issues) ("*2009 DEC Deferral Order*").

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Proceeding, DEC requested that the accounting treatment be granted "with the assurance that the Company may recover such costs in the future."[18] Thus, DEC's request for ongoing deferral treatment in the Drought Proceeding was distinguishable from the instant request for deferred accounting, as DEC did not propose a hearing process to thoroughly examine the reasonableness and prudence of the deferred costs in the near future, such as in the Companies' upcoming general rate cases.[19]

12. This request is more analogous to Commission proceedings evaluating deferral of extraordinary costs associated with environmental compliance, where the Commission has recognized and expressly mandated that the deferral period is not open-ended and the Commission and all interested parties will have full rights to address cost recovery in upcoming general rate cases.[20] Indeed, the Commission has expressly held in the past – and the Companies do not oppose here – that deferral accounting treatment of extraordinary costs is approved "without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for ratemaking purposes, if such costs are included in future rate filings,"[21] as requested by the Public Staff.[22] Of note, Public Staff and CUCA request that the Commission affirmatively further condition deferral.[23] It is not necessary for the Commission to attach any additional conditions for deferral as such amounts will be subject to the reasonable and prudent cost standard in the upcoming base rate proceedings.

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[18] *Drought Proceeding Order* at p. 19.
[19] *Drought Proceeding Order* at p. 20.
[20] *See DEC 2009 Deferral Order* at p. 19 (Mar. 31, 2009) (Commission approving deferral of costs associated with increased ownership interest in the Catawaba Nuclear Station and putting in service Allan scrubbers without instituting hearing as requested by commenters, noting that DEC was "currently contemplating filing an allocation for a general rate increase in the near term").
[21] *See, e.g., DEC 2009 Deferral Order* at p. 20.
[22] Public Staff Comments at p. 6.
[23] For example, the Public Staff asks the Commission to recognize in its order that, in light of the complexity of this proceeding, "any assumptions regarding [] rate recovery should be especially discouraged." Public Staff Comments at p. 6. The CUCA requests that the Commission "make clear" that costs related to "fines or penalties, lobbying costs or litigation related to coal ash, or any negligent coal ash practices by Duke" should not be deferred or flowed through rates. CUCA Comments at p. 2.

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3. Costs of the CCR Rule and CAMA Compliance are Properly Included in the Deferral Request

13. While the Public Staff and the Attorney General do not oppose the Companies' deferral requests, CUCA, ASU, and the Cities each in some form argue that some of the costs in question may not be eligible for deferral because Section A13 of the Statement of Financial Accounting Standards ("SFAS") No. 143[24] excludes from consideration "environmental remediation liability that results from the improper operation of a long lived asset."[25] Subsection (b) of ASC 410-20-15-3 states in full:

> An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up the spillage resulting from the normal operation of the fuel storage facility is within the scope of this Subtopic. The obligation to clean up after the catastrophic accident results from the improper use of the facility and is not within the scope of this Subtopic.

CUCA alleges (without support) that "CAMA was written in response to the Dan River spill," such that including CAMA costs in the deferral "may be counter to the standards of SFAS No. 143."[26] Building on this unsubstantiated premise, CUCA requests that the Commission "establish a deferred asset only for CCR-related Costs and allow Duke to present its argument for full recovery of all CAMA-related costs in the upcoming general rate case."[27] ASU and the Cities similarly comment that the Companies' accounting practices are "not sufficiently

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[24] SFAS No. 143 is now FASB Accounting Standards Codification ("ASC") 410-20-15-3(b), available for free with Basic View access at https://asc.fasb.org/section&trid=2175677#d3e5134-110843. For purposes of this document, we refer to the standard as using the current ASC codification.
[25] CUCA Comments at p. 3; ASU Comments at pp. 1-2; Cities Comments at pp. 1-2.
[26] CUCA Comments at p. 3.
[27] CUCA Comments at p. 3.

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transparent" such that the Companies should be required to separately account for CAMA and CCR Rule compliance costs.[28]

14. The Companies disagree with the foregoing arguments as they reflect a misunderstanding of CAMA and a misapplication of the guidance in ASC 410-20-15-3(b). As to the ARO, CAMA relates to remaining CCRs that resulted from the normal operation of generating facilities—it precludes the costs of the Dan River spill. The costs of compliance with the CCR Rule and CAMA are asset retirement liabilities, consistent with ASC 410-20-15-3(b), because the costs are based on "legal obligations associated with the retirement of [] tangible long-lived asset[s] that result from the . . . normal operation"[29] of those facilities. Environmental compliance costs associated with retirement of a long-lived asset, such as those incurred to comply with the CCR Rule and CAMA, squarely fit within the meaning of "legal obligation." As such, the costs are properly deferred as a regulatory asset pursuant to ASC 980 (formerly SFAS 71) for the reasons previously discussed in Paragraphs 7 and 8 in these Reply Comments.[30] It is not appropriate to draw a line between the CCR Rule and CAMA. The Companies are required to comply with both the CCR Rule and CAMA.

15. The primary concern underlying CUCA's, ASU's and the Cities' request appears to be ultimate cost recovery and ensuring that costs associated with fines and penalties are not passed on to customers through rates.[31] The Companies reiterate their commitment that costs

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[28] ASU Comments at pp. 3-4; Cities Comments at pp. 3-4. ASU and the Cities also request separate accounting treatment for a number of other categories, discussed in more detail in [n.38] below.

[29] *See* ASC 410-20-15-2(a). "Legal Obligation" is defined as "[a]n obligation that a party is required to settle as a result of an *existing or enacted law, statute*, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel." *See* FASB ASC Glossary, available for free with Basic View access at https://asc.fasb.org/glossarysection&trid=2175680 (emphasis added).

[30] *See* FASB ASC 980-410-25-2, available for free with Basic View access athttps://asc.fasb.org/section&trid=2560838.

[31] *See, e.g.*, CUCA Comments at p.7 (requesting that the Commission "make it clear that any . . . costs related to fines or penalties, lobbying costs or ligation related to coal ash, or any negligent coal ash practices by Duke, should

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associated with this deferral request do not include fines, penalties, or remediation costs associated with the Dan River pipe break repair and resulting spill cleanup.[32] To the extent the Intervenors are not satisfied with that commitment, the Commission will evaluate the appropriateness of cost recovery in the Companies' upcoming general rate cases. In fact, all three Intervenors that speculate about ASC 410-20-15-3(b) acknowledge that the costs will ultimately be reviewed by the Commission in a different proceeding.[33]

16. CUCA, ASU and the Cities also request a separation of CAMA costs from CCR Rule costs for purposes of the deferral.[34] It is impracticable, and in some cases impossible, to distinguish the costs of federal CCR Rule compliance from CAMA compliance. The obligations of the federal CCR Rule and CAMA are largely duplicative. To address regulatory obligations related to coal ash efficiently and comprehensively, the Companies have implemented a single compliance plan. While some costs are strictly attributable to CAMA, there is substantial overlap in the types of work required to be performed under the CCR Rule and under CAMA. It is appropriate to review the costs as a whole, as is reflected in the Companies' comprehensive compliance plan. There is nothing unusual about costs for environmental compliance being considered as programmatic in total where a confluence of requirements exists, including CAMA and the CCR Rule.

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neither be placed into the Deferred Account nor should any of these costs be flowed through to Duke's rate schedules for recovery from rate payers").

[32] Petition at p. 2.

[33] CUCA Comments at p. 3 ("A fundamental question that may be raised to this Commission, *at a later date*, is whether the costs incurred by Duke for compliance with CAMA were the result of improper operating of its coal ash ponds.") (emphasis added); ASU Comments at p. 3 ("As noted in Financial Accounting Standard 143, Asset Retirement Obligations should not be recorded for obligations that result from improper operations of an asset. These issues, undoubtedly, *will be addressed* in the upcoming rate proceedings.") (emphasis added); Cities Comments at p. 3 (making same comment as ASU).

[34] CUCA Comments at pp. 4-6; ASU Comments at p. 4; Cities Comments at p. 4.

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B. The Companies' Requested Accounting Treatment is Appropriate

17. Intervenors make several requests about the manner and timing of accounting for the deferred costs. Public Staff requests that the Commission "delay determining the beginning date of any amortization of the deferred expenses until the next respective general rate proceedings."[35] The Companies do not object to Public Staff's request. The amortization period can be determined in general rate cases to be filed later this year.

18. The Attorney General requests that the Commission order the Companies to temporarily record costs in Account 186, pending the outcome of a hearing on deferral issues.[36] Again, the Attorney General references the Drought Proceeding to support its request for this accounting treatment.[37] As discussed above, it is not necessary to hold a hearing in this proceeding. The costs are currently booked to Account 186—Miscellaneous Deferred Debits. In the Petition, the Companies requested to move the costs to Account 182.3—Other Regulatory Assets. As discussed above, the Drought Proceeding primarily involved a request to establish a new cost recovery mechanism and secondarily the request for deferral. Here, issues of cost recovery will be examined in the Companies' upcoming general rate cases. Further, the FERC Uniform System of Accounts instructions for Account 182.3 specifically contemplate that costs in that account may be excluded from rates: "[i]f rate recovery of all or part of an amount included in this account is disallowed, the disallowed amount shall be charged to Account 426.5, Other Deductions, or Account 435, Extraordinary Deductions, in the year of the disallowance."[38] Thus, granting the accounting treatment requested in the Petition would not

[35] Public Staff Comments at p. 7.
[36] Attorney General's Comments at pp. 7-8.
[37] Attorney General's Comments at pp. 7-8.
[38] 18 C.F.R. Part 101, Account 183.2(c).

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prevent the Commission from excluding a portion of the deferred costs from the Companies' rates if the Commission finds such costs were not prudently and reasonably incurred.

C. Issues Related to Cost Recovery Should Be Addressed in the Companies' Upcoming General Rate Cases

19. Intervenors' remaining arguments do not relate to the Companies' deferral request at all. Rather, Intervenors raise a litany of issues related to prudence and ultimate cost recovery,[39] all of which the Commission can fully vet in the context of a general rate case. For example, CUCA, ASU, and the Cities request that the Companies separately account for the costs subject to this proceeding.[40] The Public Staff and the Attorney General suggest that some level of cost sharing between the Companies' shareholders and customers may be appropriate.[41]

20. The Companies object to Intervenors' requests for more granular accounting of costs. For purposes of the deferral request, the Companies commit to follow generally accepted accounting principles regarding deferrals.[42] The Companies also object to Public Staff's and Attorney General's request for cost sharing between shareholders. These and other issues are superfluous and not relevant to this deferral proceeding. It would be premature for the Commission to delve into substantive review of the prudence or appropriateness of the costs sought to be treated as a regulatory asset in this proceeding because the request is expressly

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[39] *See, e.g.*, Public Staff Comments at pp. 7-8; NC WARN Comments at pp. 2-5; Attorney General's at pp. 11-13; CUCA Comments at 3; ASU Comments at 3-4; Cities Comments at 3-4.

[40] CUCA Comments at p. 6 (requesting that the Companies separate North Carolina costs from South Carolina costs and retail costs from wholesale costs); ASU Comments at p. 4 (requesting that costs be broken out into eight other categories: 1) costs related to Federal judgements; 2) costs related to EPA judgements; 3) costs associated with penalties imposed by any federal or state governmental body; 4) costs associated with complying with the terms of any of the federal or EPA proceedings listed; 5) costs incurred for lobbying efforts related to CCRs; 6) legal costs associated with coal ash-related proceedings; 7) goodwill payments made by the Companies; and 8) accrued returns); Cities Comments at p. 4 (making same request as ASU).

[41] Public Staff Comments at p. 6; Attorney General's Comments at pp. 11-13 and n.47 (citing case where Commission did not permit recovery of carrying costs associated with the cleanup of manufactured gas plants).

[42] As for ASU and the Cities' request to separate payments related to Federal, EPA, and any other judgements, as well as lobbying expenses, the Companies note that costs are not included in the Companies' deferral request. Per the Uniform System of Accounts, fines and penalties are booked in Account 426.3, and lobbying expenses are booked in Account 426.4. These are "below the line" accounts and are not part of this deferral request. The Companies decided not to include any costs for good will in their request.

limited to accounting treatment. The Companies will file a general rate case this year, as stated in the Petition. Intervenors and the Commission will have the opportunity at that time to thoroughly examine the appropriateness of cost recovery for the costs deferred as regulatory assets.

CONCLUSION

21. Because these costs meet the standard for deferral accounting—a fact that no Intervenor directly challenges—the Commission should grant the Companies' request, subject to the condition that such decision is without prejudice to the right of any party to take issue with the amount, if any, of the deferred costs to be allowed for rate making purposes, if such costs are included in future rate filings.

WHEREFORE, the Companies respectfully requests that the Commission consider these comments in reaching a decision on the Petition.

Respectfully submitted this 19th day of April, 2017.

DUKE ENERGY PROGRESS, LLC

DUKE ENERGY CAROLINAS, LLC

BY: Heather Shirley Smith

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CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC and Duke Energy Carolinas, LLC's Reply Comments in Support of its Joint Petition for an Accounting Order to Defer Environmental Compliance Costs, in Docket No. E-2 Sub 1103 and Docket No. E-7, Sub 1110, has been served on all parties of record either by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid.

This the 19th day of April, 2017

Heather Shirley Smith

Heather Shirley Smith
Deputy General Counsel
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I/A

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General's Office - McManeus Cross Exhibit 1

Duke Energy Carolinas
Response to
Attorney General's Office
Seventh Set of Data Requests
Data Request No. 7-1

Docket No. E-7, Sub 1146

Date of Request: **January 3, 2018**
Date of Response: **January 9, 2018**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to Attorney General's Office Data Request No. 7-1, was provided to me by the following individual(s): Amber D. Williams, Lead Accounting Analyst, US Property Accounting, and was provided to Attorney General under my supervision.

John T. Burnett
Deputy General Counsel
Duke Energy Carolinas

AGO 7-1

Request:

Has Duke Carolinas included in its depreciation rates any costs for closure of ash impoundments?

a. If so, specifically identify the amounts accrued, both annually and in total, and the methodology for computing them.
b. Identify and produce any reports or studies upon which such costs are based.
c. If not, explain why not.

Response:

(a) Duke has not included in its depreciation rates any costs for closure of ash impoundments.

(b) Please refer to the response in (a).

(c) No final dismantlement costs of any kind were factored into the prior DEC depreciation study. It was assumed in the last dismantlement study that the salvage received for scrap would sufficiently offset the costs to dismantle. The previous DEC dismantlement study occurred prior to the passage of the CAMA and CCR legislation. The CAMA and CCR legislation have increased estimated ash impoundment closure costs by significant amounts and are recorded in accordance with Asset Retirement Obligation accounting guidance.

Alvarez Exhibit-1

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Feb 25 2020

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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

Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement for Xcel Energy in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Appearances and Research Projects in Regulatory Proceedings

Critique of Investment in Traditional Meters (Equipped with AMR). Testimony before the New Hampshire Public Utilities Commission recommending rejection of cost recovery. DE 19-057. December 20, 2019.

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

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.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

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Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017. Also Unitil in 15-121 and Eversource in 15-122/123, March 10, 2017

Evaluation of Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of Westar Energy's Proposal To Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on Behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

Duke Energy Ohio Smart Grid Audit and Assessment. Primary research and report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

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SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

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

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

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

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The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators*. Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando, FL. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.*

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Orlando, FL. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us*. Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators*. St. Louis, MO. November 13, 2011.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization -- Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Finance, Marketing.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.

Alvarez Exhibit -2

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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**

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The attached response to NCJC Data Request No. 5-3, 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

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NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-3

Request:

5-3. Refer to Oliver testimony, Exhibit 10. Provide the estimated useful life for each of the assets listed below:
a. Page 47: Energy Storage Management System
b. Page 47: Energy Storage Projects
c. Page 51: Next Gen Cellular
d. Page 51: Mission Critical Voice
e. Page 51: POC
f. Page 51: BizWAN
g. Page 51: GridWAN
h. Page 51: Mission Critical Transport
i. Page 51: Towers/Shelters/Pow Sup
j. Page 51: Network Asset Systems
k. Page 51: Vehicle Area Network
l. Page 52: Hydraulic to Electric Reclosers
m. Page 52: Sys Intel and Monitoring
n. Page 52: Fuse Replacement
o. Page 52: UG Sys Automation
p. Page 81: Enterprise Applications
q. Page 82: Advanced Distribution Planning Tool
r. Page 83: DER Dispatch Tool
s. Page 84: Electric Transportation
t. Page 85: Power Electronics for Volt-VAR Control
u. Page 90: Substation Physical Security
v. Page 90: Windows-based unit change outs
w. Page 90: Device Entry Alert System
x. Page 90: Secure Access Device Management
y. Page 90: Line Device Protection

Response:
The list above are projects and not assets. This level of information is not available for the forecasted deferral. The depreciable lifespan of individual projects is not known prior to a project being placed in-service upon which time the capital cost for the project are unitized into the various plant FERC accounts based on the materials used. So, for the deferral estimate an estimated breakdown was made between Transmission, Distribution and General Plant spend. The average depreciation rate for each category was used.
• Distribution – 2.02% See Updated Depr Rates tab (meters were excluded from the average rate.) See Attachment CUCA 2-6 McManeus Grid Deferral Estimate

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• Transmission– 2.23% See Updated Depr Rates tab. See Attachment CUCA 2-6 McManeus Grid Deferral Estimate

CUCA 2-6 McManeus
Grid Deferral Estimate

• Advanced DMS – 10% (10-year life)
• Communications– 10% (10-year life)
• Enterprise Application & Distributed Energy – 20% (5-year life)
All of this information was supplied under Public Staff DR 1.8

DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT

NC Retail ROEs Reported in E.S.-1 and Impacts of Potential Adjustments

Note: Adjustments are estimated at a high-level and may not be at the same level of precision as would be done in a rate case.

		Q1 2019			Q2 2019		
		Income for Common Equity (in $000)	Rate Base for Common Equity (in $000)	Return on Common Equity	Income for Common Equity (in $000)	Rate Base for Common Equity (in $000)	Return on Common Equity
	ES-1 Reference	*Sched 1, Line 11, Col f*	*Sched 1, Line 11, Col c*	*Income for C.E./Rate Base for C.E.*	*Sched 1, Line 11, Col f*	*Sched 1, Line 11, Col c*	*Income for C.E./Rate Base for C.E.*
1	**As Reported**	737,546	7,304,749	10.10%	777,069	7,516,016	10.34%
2	**Adjust Equity Ratio to Last Approved**	(606)	(16,818)	0.01%	(974)	(27,043)	0.02%
3	**Normalize Weather**	(56,047)		-0.77%	(47,756)		-0.64%
4	**Remove DSM/EE PPI Incentive**	(23,449)		-0.32%	(24,469)		-0.33%
5	**Adjust to End of Period Rate Base, including Interest Sync**	(13,307)	400,166	-0.64%	(8,459)	254,377	-0.42%
6	**Annualize Depreciation Expense, including adjustment to Reserve**	(41,746)	(28,321)	-0.51%	(37,160)	(25,210)	-0.45%
8	**Spread Severance Over 3 Years**	41,733		0.54%	41,755		0.54%
9	**Adjusted**	644,125	7,659,776	8.41%	700,006	7,718,141	9.07%
	Grid Improvement Plan Impacts without Deferral						
	2020 Revenue Requirements	(10,319)	132,246	-0.28%	(10,319)	132,246	-0.28%
	2021 Revenue Requirements	(27,165)	335,682	-0.67%	(27,165)	335,682	-0.69%
	2022 Revenue Requirements	(49,835)	584,120	-1.07%	(49,835)	584,120	-1.11%

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DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT

DEC NC Summary Grid Impact

(000s)	2020	2021	2022
System CWIP Spend	442,845	580,407	702,957
NC Retail CWIP Spend	292,768	419,941	516,024
Cumulative In Service (Beg Feb 2020)	257,012	663,075	1,170,019
Accum Depr	(2,693)	(17,534)	(46,712)
Total Rate Base	254,318	645,541	1,123,307
O&M (Beg Jan 2020)	5,447	6,424	10,612
Depreciation (Beg Mar 2020)	2,693	14,840	29,178
Property Tax	-	666	1,717
Debt Return - Capital Asset	2,292	9,572	19,058
Debt Return - Deferred Balance	94	753	2,336
Equity Return - Capital Asset	7,033	29,377	58,488
Equity Return - Deferred Balance	288	2,311	7,171
Annual Deferral	17,847	63,943	128,561
Cumulative Balance Deferral Balance	17,847	81,790	210,351

I/A

DUKE ENERGY CAROLINAS, LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN MULTI YEAR RATE PLAN
For the period January, 2020 through December 31, 2022

Line No.	Calculation of North Carolina Retail Costs	2019 Dec	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	2021 Jun	2021 Jul	2021 Aug	2021 Sep	2021 Oct	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec
1	Plant-in-Service: [1]																																			
2	Distribution to Plant in Service	-	-	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	13,210,021	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	23,177,334	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178	30,018,178
3	Transmission to Plant in Service	-	-	4,784,997	4,784,997	4,784,997	4,784,997	4,784,997	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,163,017	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,444,291	7,608,302	7,608,302	7,608,302	7,608,302	7,608,302
4	Advanced DMS Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-	9,327,310	-	-	-	-	-	-	-	-	-	-	8,793,258	-	-	-	-	-	-	-	-	-	-	11,517,212
5	Communications Plant in Service	-	-	1,627,514	1,627,514	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,249,207	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	2,989,928	3,408,102	3,408,102	3,408,102	3,408,102	3,408,102	3,408,102	3,408,102	3,408,102
6	Enterprise Application & Distributed Energy Plant in Service	-	-	-	-	-	-	-	-	-	-	-	-	11,973,249	-	-	-	-	-	-	-	-	-	-	7,808,788	-	-	-	-	-	-	-	-	-	-	12,091,341
7	Cumulative Distribution investment (L2)	-	-	13,210,021	26,420,043	39,630,064	52,840,086	66,050,107	79,260,128	92,470,150	105,680,171	118,890,193	132,100,214	145,310,235	158,520,257	181,697,591	204,874,925	228,052,258	251,229,592	274,406,926	297,584,260	320,761,594	343,938,928	367,116,262	390,293,596	413,470,929	436,648,263	466,666,442	496,684,620	526,702,798	556,720,976	586,739,154	616,757,333	646,775,511	676,793,689	706,811,867	736,830,045	766,848,224
8	Cumulative Transmission investment (L3)	-	-	4,784,997	9,569,993	14,354,990	19,139,986	23,924,983	31,088,000	38,251,018	45,414,035	52,577,053	59,740,070	66,903,087	74,066,105	81,229,122	88,392,140	95,555,157	102,718,175	109,881,192	117,325,483	124,769,774	132,214,065	139,658,356	147,102,647	154,546,938	161,991,229	169,435,520	176,879,811	184,324,102	191,768,393	199,212,684	206,820,986	214,429,289	222,037,591	229,645,893	237,254,196	244,862,498
9	Cumulative Advanced DMS investment (L4)	-	-	-	-	-	-	-	-	-	-	-	-	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	9,327,310	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	18,120,568	29,637,780
10	Cumulative Communication investment (L5)	-	-	1,627,514	3,255,029	5,504,236	7,753,443	10,002,650	12,251,857	14,501,065	16,750,272	18,999,479	21,248,686	23,497,893	25,747,100	27,996,307	30,245,515	33,235,443	36,225,371	39,215,299	42,205,227	45,195,155	48,185,083	51,175,011	54,164,939	57,154,867	60,144,795	63,134,723	66,124,651	69,532,753	72,940,855	76,348,957	79,757,059	83,165,160	86,573,262	89,981,364	93,389,466	96,797,568
11	Cumulative Enterprise Application & Distributed Energy investment (L6)	-	-	-	-	-	-	-	-	-	-	-	-	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	11,973,249	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	19,782,037	31,873,378
12																																				
13	Accumulated depreciation & amortization:																																			
14	Distribution plant depreciation rate [2]	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	1.98%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%	2.02%
15	Transmission plant depreciation rate [2]	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.05%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%	2.23%
16	Advance DMS plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
17	Communication plant depreciation rate [2]	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%	10.00%
18	Enterprise Application & Distributed Energy plant depreciation rate [2]	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%	20.00%
19	Distribution depreciation expense (L7 * L14)	-	-	-	21,797	43,593	65,390	87,186	108,983	133,421	155,658	177,895	200,132	222,369	244,606	266,842	305,858	344,873	383,888	422,903	461,918	500,934	539,949	578,964	617,979	656,994	696,009	735,025	785,555	836,086	886,616	937,147	987,678	1,038,208	1,088,739	1,139,269	1,189,800	1,240,331
20	Transmission depreciation expense (L8 * L15)	-	-	-	8,174	16,349	24,523	32,697	40,872	57,772	71,083	84,394	97,706	111,017	124,328	137,640	150,951	164,262	177,573	190,885	204,196	218,030	231,864	245,698	259,532	273,366	287,200	301,034	314,868	328,702	342,536	356,370	370,204	384,342	398,481	412,620	426,759	440,897
21	Advanced DMS depreciation expense (L9 * L16)	-	-	-	-	-	-	-	-	-	-	-	-	-	77,728	77,728	77,728	77,728	77,728	77,728	77,728	77,728	77,728	77,728	77,728	151,005	151,005	151,005	151,005	151,005	151,005	151,005	151,005	151,005	151,005	151,005	151,005
22	Communication depreciation expense (L10 * L17)	-	-	-	13,563	27,125	45,869	64,612	83,355	102,099	120,842	139,586	158,329	177,072	195,816	214,559	233,303	252,046	276,962	301,878	326,794	351,710	376,626	401,542	426,458	451,374	476,291	501,207	526,123	551,039	579,440	607,840	636,241	664,642	693,043	721,444	749,845	778,246
23	Enterprise Application & Distributed Energy depreciation expense (L11 * L18)	-	-	-	-	-	-	-	-	-	-	-	-	-	199,554	199,554	199,554	199,554	199,554	199,554	199,554	199,554	199,554	199,554	199,554	329,701	329,701	329,701	329,701	329,701	329,701	329,701	329,701	329,701	329,701	329,701
24	Distribution accumulated depreciation	-	-	-	(21,797)	(65,390)	(130,779)	(217,965)	(326,948)	(460,369)	(616,027)	(793,922)	(994,054)	(1,216,423)	(1,461,028)	(1,727,871)	(2,033,728)	(2,378,601)	(2,762,489)	(3,185,392)	(3,647,311)	(4,148,244)	(4,688,193)	(5,267,157)	(5,885,136)	(6,542,130)	(7,238,139)	(7,973,164)	(8,758,719)	(9,594,805)	(10,481,421)	(11,418,568)	(12,406,246)	(13,444,454)	(14,533,193)	(15,672,462)	(16,862,262)	(18,102,593)
25	Transmission accumulated depreciation	-	-	-	(8,174)	(24,523)	(49,046)	(81,744)	(122,616)	(180,387)	(251,471)	(335,865)	(433,571)	(544,588)	(668,916)	(806,555)	(957,506)	(1,121,768)	(1,299,342)	(1,490,226)	(1,694,422)	(1,912,452)	(2,144,316)	(2,390,014)	(2,649,545)	(2,922,911)	(3,210,111)	(3,511,145)	(3,826,012)	(4,154,714)	(4,497,249)	(4,853,619)	(5,223,823)	(5,608,165)	(6,006,646)	(6,419,266)	(6,846,025)	(7,286,922)
26	Advanced DMS accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	(77,728)	(155,455)	(233,183)	(310,910)	(388,638)	(466,366)	(544,093)	(621,821)	(699,548)	(777,276)	(855,003)	(932,731)	(1,083,736)	(1,234,741)	(1,385,745)	(1,536,750)	(1,687,755)	(1,838,759)	(1,989,764)	(2,140,769)	(2,291,774)	(2,442,778)	(2,593,783)	(2,744,788)
27	Communication accumulated depreciation	-	-	-	(13,563)	(40,688)	(86,556)	(151,169)	(234,524)	(336,623)	(457,465)	(597,051)	(755,380)	(932,452)	(1,128,268)	(1,342,827)	(1,576,129)	(1,828,175)	(2,105,137)	(2,407,015)	(2,733,810)	(3,085,520)	(3,462,146)	(3,863,689)	(4,290,147)	(4,741,521)	(5,217,812)	(5,719,019)	(6,245,141)	(6,796,180)	(7,375,620)	(7,983,460)	(8,619,701)	(9,284,344)	(9,977,387)	(10,698,830)	(11,448,675)	(12,226,921)
28	Enterprise Application & Distributed Energy accumulated depreciation	-	-	-	-	-	-	-	-	-	-	-	-	-	(199,554)	(399,108)	(598,662)	(798,217)	(997,771)	(1,197,325)	(1,396,879)	(1,596,433)	(1,795,987)	(1,995,542)	(2,195,096)	(2,394,650)	(2,724,350)	(3,054,051)	(3,383,752)	(3,713,452)	(4,043,153)	(4,372,854)	(4,702,554)	(5,032,255)	(5,361,955)	(5,691,656)	(6,021,357)	(6,351,057)

I/A

DUKE ENERGY CAROLINAS, LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN MULTI YEAR RATE PLAN
For the period January, 2020 through December 31, 2022

Line No.	Calculation of North Carolina Retail Costs Description	2019 Dec	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	2021 Jun	2021 Jul	2021 Aug	2021 Sep	2021 Oct	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec
29																																					
30	Net electric plant																																				
31	Distribution (L7 + L24)	-	-	13,210,021	26,398,246	39,564,675	52,709,306	65,832,142	78,933,180	92,009,781	105,064,144	118,096,270	131,106,160	144,093,813	157,059,228	179,969,720	202,841,196	225,673,657	248,467,103	271,221,534	293,936,949	316,613,350	339,250,735	361,849,105	384,408,460	406,928,800	429,410,124	458,693,278	487,925,901	517,107,993	546,239,555	575,320,586	604,351,087	633,331,057	662,260,496	691,139,405	719,967,783	748,745,631
32	Transmission (L8 + L25)	-	-	4,784,997	9,561,819	14,330,467	19,090,940	23,843,239	30,965,385	38,070,630	45,162,565	52,241,188	59,306,499	66,358,500	73,397,189	80,422,567	87,434,634	94,433,389	101,418,833	108,390,966	115,631,061	122,857,322	130,069,749	137,268,343	144,453,102	151,624,027	158,781,118	165,924,376	173,053,799	180,169,388	187,271,144	194,359,065	201,597,164	208,821,124	216,030,945	223,226,627	230,408,171	237,575,576
33	Advanced DMS (L9 + L26)	-	-	-	-	-	-	-	-	-	-	-	-	9,327,310	9,249,583	9,171,855	9,094,128	9,016,400	8,938,672	8,860,945	8,783,217	8,705,490	8,627,762	8,550,035	8,472,307	17,187,837	17,036,832	16,885,828	16,734,823	16,583,818	16,432,813	16,281,809	16,130,804	15,979,799	15,828,794	15,677,790	15,526,785	26,892,992
34	Communication (L10 + L27)	-	-	1,627,514	3,241,466	5,463,548	7,666,887	9,851,482	12,017,333	14,164,442	16,292,807	18,402,428	20,493,306	22,565,441	24,618,833	26,653,481	28,669,385	31,407,267	34,120,233	36,808,283	39,471,417	42,109,635	44,722,937	47,311,322	49,874,792	52,413,345	54,926,983	57,415,704	59,879,510	62,736,573	65,565,235	68,365,496	71,137,357	73,880,817	76,595,876	79,282,534	81,940,791	84,570,647
35	Enterprise Application & Distributed Energy (L11 + L28)	-	-	-	-	-	-	-	-	-	-	-	-	11,973,249	11,773,695	11,574,141	11,374,587	11,175,032	10,975,478	10,775,924	10,576,370	10,376,816	10,177,262	9,977,708	9,778,153	17,387,387	17,057,687	16,727,986	16,398,285	16,068,585	15,738,884	15,409,184	15,079,483	14,749,782	14,420,082	14,090,381	13,760,680	25,522,321
36	Average rate base - Distribution	-	-	6,605,011	19,804,134	32,981,460	46,136,990	59,270,724	72,382,661	85,471,480	98,536,962	111,580,207	124,601,215	137,599,986	150,576,521	168,514,474	191,405,458	214,257,427	237,070,380	259,844,319	282,579,242	305,275,150	327,932,042	350,549,920	373,128,782	395,668,630	418,169,462	444,051,701	473,309,589	502,516,947	531,673,774	560,780,071	589,835,836	618,841,072	647,795,776	676,699,951	705,553,594	734,356,707
37	Average rate base - Transmission	-	-	2,392,498	7,173,408	11,946,143	16,710,703	21,467,090	27,404,312	34,518,007	41,616,597	48,701,876	55,773,843	62,832,500	69,877,844	76,909,878	83,928,600	90,934,011	97,926,111	104,904,900	112,011,014	119,244,192	126,463,536	133,669,046	140,860,722	148,038,564	155,202,573	162,352,747	169,489,087	176,611,594	183,720,266	190,815,104	197,978,114	205,209,144	212,426,034	219,628,786	226,817,399	233,991,874
38	Average rate base - Advanced DMS	-	-	-	-	-	-	-	-	-	-	-	-	4,663,655	9,288,447	9,210,719	9,132,991	9,055,264	8,977,536	8,899,809	8,822,081	8,744,354	8,666,626	8,588,898	8,511,171	12,830,072	17,112,335	16,961,330	16,810,325	16,659,320	16,508,316	16,357,311	16,206,306	16,055,302	15,904,297	15,753,292	15,602,287	21,209,888
39	Average rate base - Communication	-	-	813,757	2,434,490	4,352,507	6,565,217	8,759,184	10,934,408	13,090,888	15,228,624	17,347,618	19,447,867	21,529,374	23,592,137	25,636,157	27,661,433	30,038,326	32,763,750	35,464,258	38,139,850	40,790,526	43,416,286	46,017,129	48,593,057	51,144,069	53,670,164	56,171,344	58,647,607	61,308,041	64,150,904	66,965,366	69,751,427	72,509,087	75,238,346	77,939,205	80,611,662	83,255,719
40	Average rate base - Enterprise Application & Distributed Energy	-	-	-	-	-	-	-	-	-	-	-	-	5,986,625	11,873,472	11,673,918	11,474,364	11,274,809	11,075,255	10,875,701	10,676,147	10,476,593	10,277,039	10,077,485	9,877,930	13,582,770	17,222,537	16,892,836	16,563,136	16,233,435	15,903,734	15,574,034	15,244,333	14,914,633	14,584,932	14,255,231	13,925,531	19,641,501
41																																					
42	Return on rate base:																																				
43	Long-term debt	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%	2.188%
44	Members' equity	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%	6.716%
45	Distribution Debt return on rate base (L36 x L43 / 12)		-	12,045	36,117	60,148	84,139	108,091	132,003	155,873	179,701	203,487	227,234	250,939	274,605	307,318	349,064	390,739	432,342	473,875	515,336	556,726	598,046	639,294	680,470	721,576	762,610	809,812	863,169	916,434	969,607	1,022,688	1,075,676	1,128,573	1,181,377	1,234,089	1,286,709	1,339,237
46	Transmission Debt return on rate base (L37 x L43 / 12)		-	4,363	13,082	21,786	30,475	39,149	49,977	62,950	75,896	88,817	101,714	114,587	127,435	140,260	153,060	165,835	178,587	191,314	204,273	217,464	230,630	243,771	256,886	269,976	283,041	296,081	309,095	322,084	335,048	347,987	361,050	374,237	387,399	400,534	413,644	426,728
47	Advance DMS Debt return on rate base (L38 x L43 / 12)		-	-	-	-	-	-	-	-	-	-	-	8,505	16,939	16,797	16,656	16,514	16,372	16,230	16,089	15,947	15,805	15,663	15,522	23,398	31,208	30,932	30,657	30,381	30,106	29,831	29,555	29,280	29,004	28,729	28,454	38,680
48	Communication Debt return on rate base (L39 x L43 / 12)		-	1,484	4,440	7,938	11,973	15,974	19,941	23,874	27,772	31,637	35,467	39,263	43,025	46,752	50,446	54,781	59,751	64,676	69,555	74,389	79,178	83,921	88,619	93,271	97,878	102,439	106,955	111,807	116,991	122,124	127,205	132,234	137,211	142,137	147,010	151,832
49	Enterprise Application & Distributed Energy Debt return on rate base (L40 x L43 / 12)		-	-	-	-	-	-	-	-	-	-	-	10,918	21,654	21,290	20,926	20,562	20,198	19,834	19,470	19,106	18,742	18,378	18,014	24,771	31,409	30,807	30,206	29,605	29,003	28,402	27,801	27,200	26,598	25,997	25,396	35,820
50	Distribution Equity return on rate base (L36 x L44 / 12)		-	36,968	110,842	184,594	258,224	331,732	405,118	478,375	551,501	624,502	697,379	770,132	842,760	943,157	1,071,275	1,199,175	1,326,857	1,454,320	1,581,565	1,708,592	1,835,400	1,961,990	2,088,361	2,214,514	2,340,449	2,485,309	2,649,062	2,812,532	2,975,720	3,138,625	3,301,247	3,463,586	3,625,642	3,787,416	3,948,906	4,110,114
51	Transmission Equity return on rate base (L37 x L44 / 12)		-	13,391	40,149	66,861	93,528	120,149	153,379	193,194	232,924	272,579	312,160	351,667	391,099	430,456	469,739	508,948	548,082	587,141	626,913	667,397	707,803	748,131	788,382	828,556	868,652	908,671	948,612	988,476	1,028,262	1,067,971	1,108,062	1,148,533	1,188,925	1,229,238	1,269,472	1,309,627
52	Advance DMS Equity return on rate base (L38 x L44 / 12)		-	-	-	-	-	-	-	-	-	-	-	26,102	51,986	51,551	51,116	50,681	50,246	49,811	49,376	48,941	48,506	48,071	47,636	71,809	95,776	94,931	94,086	93,240	92,395	91,550	90,705	89,860	89,015	88,169	87,324	118,709
53	Communication Equity return on rate base (L39 x L44 / 12)		-	4,555	13,626	24,361	36,745	49,024	61,199	73,268	85,233	97,093	108,848	120,498	132,043	143,483	154,818	168,121	183,375	198,490	213,465	228,300	242,996	257,553	271,970	286,248	300,386	314,385	328,244	343,134	359,046	374,798	390,391	405,825	421,101	436,217	451,175	465,973
54	Enterprise Application & Distributed Energy Equity return on rate base (L40 x L44 / 12)		-	-	-	-	-	-	-	-	-	-	-	33,506	66,455	65,338	64,221	63,104	61,987	60,870	59,753	58,636	57,519	56,403	55,286	76,021	96,393	94,547	92,702	90,857	89,011	87,166	85,321	83,476	81,630	79,785	77,940	109,931
55																																					
56	Other operation and maintenance expense: [3]																																				
57	Distribution O&M		233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761
58	Transmission O&M		70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467
59	General Plant O&M		557,355	557,355	557,355	557,355	557,355	557,355	557,355	557,355	557,355	557,355	557,355	557,355	530,911	530,911	530,911	530,911	530,911	530,911	530,911	530,911	530,911	530,911	530,911	530,911	717,527	717,527	717,527	717,527	717,527	717,527	717,527	717,527	717,527	717,527	717,527
60	Total O&M	-	861,921	861,921	861,921	861,921	861,921	861,921	861,921	861,921	861,921	861,921	861,921	861,921	943,337	943,337	943,337	943,337	943,337	943,337	943,337	943,337	943,337	943,337	943,337	943,337	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307
61																																					
62	2018 Grid O&M Threshhold	Annual Threshold																																			
63	Distribution	(174,727)	59,109	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	233,836	161,232	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	335,959	330,033	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761	504,761
64	Transmission		70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	70,729	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	76,467	70,019	70,019	70,019	70,019	70,019	70,019	70,019	70,019	70,019	70,019	70,019
65	General Plant	(4,721,392)	(4,164,037)	(3,606,682)	(3,049,327)	(2,491,972)	(1,934,617)	(1,377,262)	(819,907)	(262,552)	294,803	557,355	557,355	557,355	(4,190,481)	(3,659,570)	(3,128,660)	(2,597,749)	(2,066,838)	(1,535,927)	(1,005,017)	(474,106)	56,805	530,911	530,911	530,911	(4,003,865)	(3,286,337)	(2,568,810)	(1,851,283)	(1,133,756)	(416,228)	301,299	717,527	717,527	717,527	717,527
66																																					
67	Depreciation and amortization:																																				
68	Distribution depreciation expense (L19)	-	-	-	21,797	43,593	65,390	87,186	108,983	133,421	155,658	177,895	200,132	222,369	244,606	266,842	305,858	344,873	383,888	422,903	461,918	500,934	539,949	578,964	617,979	656,994	696,009	735,025	785,555	836,086	886,616	937,147	987,678	1,038,208	1,088,739	1,139,269	1,189,800	1,240,331
69	Transmission depreciation expense (L20)	-	-	-	8,174	16,349	24,523	32,697	40,872	57,772	71,083	84,394	97,706	111,017	124,328	137,640	150,951	164,262	177,573	190,885	204,196	218,030	231,864	245,698	259,532	273,366	287,200	301,034	314,868	328,702	342,536	356,370	370,204	384,342	398,481	412,620	426,759	440,897
70	General plant depreciation expense (sum (L21:23))	-	-	-	13,563	27,125	45,869	64,612	83,355	102,099	120,842	139,586	158,329	177,072	473,098	491,841	510,584	529,328	554,244	579,160	604,076	628,992	653,908	678,824	703,740	728,656	956,996	981,912	1,006,828	1,031,744	1,060,145	1,088,546	1,116,947	1,145,348	1,173,748	1,202,149	1,230,550	1,258,951
71	Total Depreciation	-	-	-	43,534	87,067	135,781	184,496	233,210	293,292	347,583	401,875	456,167	510,458	842,031	896,323	967,393	1,038,463	1,115,705	1,192,948	1,270,190	1,347,955	1,425,721	1,503,486	1,581,251	1,659,016	1,940,205	2,017,970	2,107,251	2,196,532	2,289,297	2,382,062	2,474,828	2,567,898	2,660,968	2,754,038	2,847,109	2,940,179
72																																					
73	General taxes:																																				
74	Property tax rate - Combined North Carolina and South Carolina	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%	0.26%
75																																					
76	Distribution property tax expense		-	-	-	-	-	-	-	-	-	-	-	-	31,364	31,364	31,364	31,364	31,364	31,364	31,364	31,364	31,364	31,364	31,364	31,364	89,245	89,245	89,245	89,245	89,245	89,245	89,245	89,245	89,245	89,245	89,245
77	Transmission property tax expense		-	-	-	-	-	-	-	-	-	-	-	-	14,441	14,441	14,441	14,441	14,441	14,441	14,441	14,441	14,441	14,441	14,441	14,441	33,358	33,358	33,358	33,358	33,358	33,358	33,358	33,358	33,358	33,358	33,358
78	General Plant property tax expense		-	-	-	-	-	-	-	-	-	-	-	-	9,669	9,669	9,669	9,669	9,669	9,669	9,669	9,669	9,669	9,669	9,669	9,669	20,518	20,518	20,518	20,518	20,518	20,518	20,518	20,518	20,518	20,518	20,518
79	Impact to general taxes (Sum (L76:L78))		-	-	-	-	-	-	-	-	-	-	-	-	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121

I/A

DUKE ENERGY CAROLINAS, LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT PLAN MULTI YEAR RATE PLAN
For the period January, 2020 through December 31, 2022

Line No.	Calculation of North Carolina Retail Costs Description	2019 Dec	2020 Jan	2020 Feb	2020 Mar	2020 Apr	2020 May	2020 Jun	2020 Jul	2020 Aug	2020 Sep	2020 Oct	2020 Nov	2020 Dec	2021 Jan	2021 Feb	2021 Mar	2021 Apr	2021 May	2021 Jun	2021 Jul	2021 Aug	2021 Sep	2021 Oct	2021 Nov	2021 Dec	2022 Jan	2022 Feb	2022 Mar	2022 Apr	2022 May	2022 Jun	2022 Jul	2022 Aug	2022 Sep	2022 Oct	2022 Nov	2022 Dec
80																																					
81	Total impact to operating income:																																				
82	Distribution (if L63>0 Then L63 + L68 + L76 else + L68 + L76)	-	59,109	233,836	255,633	277,429	299,226	321,022	342,819	367,257	389,494	411,731	433,968	456,205	437,202	634,166	673,181	712,196	751,212	790,227	829,242	868,257	907,272	946,287	985,303	1,024,318	1,115,288	1,329,031	1,379,561	1,430,092	1,480,622	1,531,153	1,581,684	1,632,214	1,682,745	1,733,275	1,783,806	1,834,337
83	Transmission (if L64>0 Then L64 + L69 + L77 else + L69 + L77)	-	70,729	70,729	78,904	87,078	95,252	103,427	111,601	128,501	141,812	155,124	168,435	181,746	215,236	228,547	241,858	255,170	268,481	281,792	295,103	308,937	322,771	336,605	350,439	364,273	390,577	404,411	418,245	432,079	445,913	459,747	473,581	487,719	501,858	515,997	530,136	544,275
84	General Plant (if L65>0 Then L65 + L70 + L78 else + L70 + L78)	-	-	-	13,563	27,125	45,869	64,612	83,355	102,099	415,645	696,941	715,684	734,427	482,767	501,510	520,254	538,997	563,913	588,829	613,745	638,661	720,382	1,219,404	1,244,320	1,269,236	977,514	1,002,430	1,027,346	1,052,262	1,080,663	1,109,063	1,438,763	1,883,392	1,911,793	1,940,194	1,968,595	1,996,996
85																																					
86	Total impact to operating income:																																				
87	Distribution impact to operating income (L45 + L50 + L82)	-	59,109	282,849	402,591	522,171	641,589	760,845	879,940	1,001,505	1,120,696	1,239,721	1,358,581	1,477,276	1,554,567	1,884,641	2,093,520	2,302,110	2,510,411	2,718,422	2,926,143	3,133,575	3,340,718	3,547,571	3,754,134	3,960,408	4,218,347	4,624,151	4,891,792	5,159,058	5,425,949	5,692,465	5,958,607	6,224,373	6,489,764	6,754,780	7,019,422	7,283,688
88	Transmission impact to operating income (L46 + L51 + L83)	-	70,729	88,483	132,135	175,725	219,256	262,725	314,957	384,645	450,632	516,520	582,309	648,000	733,770	799,263	864,657	929,953	995,149	1,060,247	1,126,290	1,193,798	1,261,204	1,328,507	1,395,707	1,462,805	1,542,270	1,609,162	1,675,952	1,742,639	1,809,223	1,875,705	1,942,693	2,010,490	2,078,182	2,145,770	2,213,252	2,280,630
89	General plant impact to operating income (sum(L47:49) + sum(L52:54) + L84)	-	-	6,039	31,628	59,423	94,586	129,610	164,495	199,241	528,651	825,670	859,998	973,219	814,868	846,722	878,436	912,760	955,843	998,740	1,041,453	1,083,981	1,183,129	1,699,393	1,741,367	1,844,754	1,630,562	1,670,471	1,710,195	1,751,286	1,797,216	1,842,934	2,189,741	2,651,267	2,696,353	2,741,229	2,785,894	2,917,942
90	Total	-	129,838	377,371	566,353	757,320	955,431	1,153,181	1,359,392	1,585,391	2,099,978	2,581,911	2,800,889	3,098,495	3,103,205	3,530,625	3,836,614	4,144,823	4,461,403	4,777,409	5,093,887	5,411,355	5,785,051	6,575,471	6,891,208	7,267,967	7,391,179	7,903,784	8,277,939	8,652,983	9,032,388	9,411,105	10,091,040	10,886,129	11,264,299	11,641,779	12,018,567	12,482,260
91	Distribution Cumulative impact to operating income	-	59,109	342,126	745,859	1,271,127	1,918,461	2,688,394	3,581,461	4,600,835	5,744,851	7,014,061	8,409,011	9,930,253	11,537,101	13,482,942	15,647,791	18,032,950	20,639,383	23,468,059	26,519,954	29,796,049	33,297,330	37,024,791	40,979,427	45,162,243	49,626,204	54,520,624	59,709,371	65,194,135	70,976,227	77,056,963	83,437,669	90,119,677	97,104,327	104,392,966	111,986,949	119,887,639
92	Transmission Cumulative impact to operating income	-	70,729	159,414	292,203	469,215	690,639	956,669	1,276,320	1,667,329	2,126,350	2,653,683	3,249,617	3,914,444	4,668,636	5,492,366	6,385,990	7,349,806	8,384,115	9,489,220	10,666,468	11,917,732	13,243,328	14,643,574	16,118,793	17,669,311	19,307,921	21,022,517	22,813,466	24,681,098	26,625,748	28,647,751	30,748,054	32,927,909	35,187,663	37,527,664	39,948,266	42,449,821
93	General Plant Cumulative impact to operating income	-	-	6,039	37,684	97,231	192,202	322,636	488,598	690,150	1,222,159	2,053,277	2,922,606	3,910,003	4,744,342	5,615,732	6,523,701	7,471,069	8,466,810	9,510,990	10,603,700	11,745,031	12,991,882	14,761,807	16,582,303	18,516,422	20,247,056	22,028,052	23,858,789	25,740,917	27,679,562	29,674,823	32,028,108	34,855,319	37,742,383	40,690,617	43,700,157	46,858,736
94																																					
95	Balance for return																																				
96	Distribution Balance for Return ((L87 + L103 + L106) + Current Month L87 /2)	-	29,555	200,702	544,563	1,010,042	1,597,667	2,307,971	3,141,491	4,100,082	5,184,504	6,394,200	7,729,721	9,191,615	10,759,817	12,540,621	14,601,031	16,881,895	19,384,177	22,108,848	25,056,882	28,229,261	31,626,972	35,251,005	39,102,360	43,182,039	47,517,030	52,208,549	57,263,475	62,614,606	68,263,252	74,210,731	80,458,366	87,007,491	93,859,445	101,015,576	108,477,238	116,245,795
97	Transmission Balance for Return ((L88 + L104 + L107) + Current Month L88 /2)	-	35,365	115,172	226,136	381,352	581,012	825,307	1,118,842	1,475,006	1,901,034	2,395,423	2,958,462	3,590,444	4,301,751	5,092,735	5,953,661	6,884,830	7,886,541	8,959,096	10,103,323	11,320,833	12,612,726	13,979,320	15,420,940	16,937,908	18,536,786	20,217,936	21,975,490	23,809,779	25,721,136	27,709,898	29,776,707	31,922,664	34,148,572	36,454,780	38,841,640	41,309,506
98	General Plant Balance for Return ((L89 + L105 + L108) + Current Month L89 /2)	-	-	3,019	21,870	67,520	144,909	257,831	406,350	590,529	957,834	1,640,442	2,492,607	3,423,393	4,336,908	5,192,371	6,084,483	7,014,689	7,988,889	9,011,620	10,082,973	11,203,041	12,400,317	13,912,110	15,711,620	17,594,045	19,431,775	21,192,817	23,003,692	24,865,274	26,780,955	28,753,356	30,933,238	33,529,685	36,394,207	39,320,003	42,307,210	45,399,765
99																																					
100	Return on Deferred Balance																																				
101	After Tax Long-term debt	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%	1.677%
102	After Tax Members' equity	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%	5.148%
103	Distribution Debt return on rate base (L96 x L101 / 12)	-	41	281	761	1,412	2,233	3,226	4,391	5,731	7,247	8,938	10,805	12,849	15,041	17,530	20,410	23,598	27,096	30,905	35,026	39,460	44,210	49,276	54,659	60,362	66,422	72,980	80,046	87,526	95,422	103,736	112,469	121,624	131,202	141,205	151,635	162,494
104	Transmission Debt return on rate base (L97 x L101 / 12)	-	49	161	316	533	812	1,154	1,564	2,062	2,657	3,348	4,135	5,019	6,013	7,119	8,322	9,624	11,024	12,523	14,123	15,825	17,631	19,541	21,556	23,677	25,912	28,262	30,718	33,283	35,954	38,734	41,623	44,623	47,735	50,958	54,295	57,745
105	General Plant Debt return on rate base (L98 x L101 / 12)	-	-	4	31	94	203	360	568	825	1,339	2,293	3,484	4,785	6,062	7,258	8,505	9,805	11,167	12,597	14,094	15,660	17,334	19,447	21,963	24,594	27,163	29,624	32,156	34,758	37,436	40,193	43,240	46,870	50,874	54,964	59,139	63,462
106	Distribution Equity return on rate base (L96 x L101 / 12)	-	127	861	2,336	4,333	6,854	9,901	13,477	17,589	22,242	27,431	33,161	39,432	46,160	53,799	62,638	72,423	83,158	94,847	107,494	121,104	135,680	151,227	167,749	185,251	203,848	223,975	245,660	268,617	292,849	318,364	345,166	373,262	402,657	433,357	465,367	498,694
107	Transmission Equity return on rate base (L97 x L101 / 12)	-	152	494	970	1,636	2,493	3,541	4,800	6,328	8,155	10,276	12,692	15,403	18,455	21,848	25,541	29,536	33,833	38,435	43,343	48,566	54,109	59,971	66,156	72,664	79,523	86,735	94,275	102,144	110,344	118,875	127,742	136,948	146,497	156,391	166,631	177,218
108	General Plant Equity return on rate base (L98 x L101 / 12)	-	-	13	94	290	622	1,106	1,743	2,533	4,109	7,037	10,693	14,686	18,605	22,275	26,102	30,093	34,272	38,660	43,256	48,061	53,197	59,683	67,403	75,478	83,362	90,917	98,686	106,672	114,890	123,352	132,704	143,842	156,131	168,683	181,498	194,765
109	Total	-	369	1,814	4,508	8,298	13,216	19,288	26,543	35,069	45,750	59,325	74,970	92,174	110,336	129,829	151,520	175,080	200,551	227,967	257,336	288,676	322,160	359,145	399,486	442,026	486,229	532,493	581,541	632,999	686,895	743,254	802,944	867,169	935,095	1,005,557	1,078,565	1,154,378
110																																					
111	Total																																				
112	Distribution deferral (L87 + L103 + L106)	-	59,277	283,991	405,688	527,916	650,676	773,973	897,808	1,024,826	1,150,184	1,276,090	1,402,547	1,529,557	1,615,767	1,955,970	2,176,569	2,398,132	2,620,665	2,844,174	3,068,663	3,294,139	3,520,607	3,748,073	3,976,542	4,206,021	4,488,617	4,921,105	5,217,498	5,515,201	5,814,220	6,114,565	6,416,242	6,719,258	7,023,623	7,329,342	7,636,424	7,944,877
113	Transmission deferral (L88 + L104 + L107)	-	70,930	89,138	133,421	177,894	222,560	267,419	321,321	393,034	461,444	530,145	599,136	668,422	758,238	828,230	898,521	969,112	1,040,007	1,111,205	1,183,756	1,258,189	1,332,943	1,408,019	1,483,419	1,559,145	1,647,704	1,724,159	1,800,945	1,878,065	1,955,521	2,033,315	2,112,058	2,192,061	2,272,414	2,353,119	2,434,178	2,515,592
114	General deferral (L89 + L105 + L108)	-	-	6,056	31,752	59,807	95,411	131,077	166,806	202,600	534,099	835,001	874,176	992,691	839,536	876,255	913,044	952,658	1,001,282	1,049,997	1,098,804	1,147,703	1,253,660	1,778,523	1,830,732	1,944,826	1,741,087	1,791,013	1,841,037	1,892,716	1,949,542	2,006,479	2,365,685	2,841,978	2,903,358	2,964,875	3,026,531	3,176,169
115	Total Sum (L112:L114)	-	130,208	379,185	570,861	765,618	968,647	1,172,469	1,385,936	1,620,460	2,145,727	2,641,235	2,875,859	3,190,669	3,213,540	3,660,455	3,988,133	4,319,903	4,661,954	5,005,376	5,351,223	5,700,031	6,107,211	6,934,616	7,290,694	7,709,992	7,877,408	8,436,277	8,859,480	9,285,982	9,719,283	10,154,359	10,893,985	11,753,298	12,199,395	12,647,336	13,097,132	13,636,638
116																																					

[1] Based on lag time assumptions noted on Page 6
[2] Per accounting.
[3] From page 6.

	Summary																																				
	O&M	-	129,838	304,566	304,566	304,566	304,566	304,566	304,566	304,566	599,369	861,921	861,921	861,921	237,699	412,426	412,426	412,426	412,426	412,426	412,426	412,426	469,231	943,337	943,337	943,337	400,052	574,780	574,780	574,780	574,780	574,780	876,078	1,292,307	1,292,307	1,292,307	1,292,307	1,292,307
	Depreciation	-	-	-	43,534	87,067	135,781	184,496	233,210	293,292	347,583	401,875	456,167	510,458	842,031	896,323	967,393	1,038,463	1,115,705	1,192,948	1,270,190	1,347,955	1,425,721	1,503,486	1,581,251	1,659,016	1,940,205	2,017,970	2,107,251	2,196,532	2,289,297	2,382,062	2,474,828	2,567,898	2,660,968	2,754,038	2,847,109	2,940,179
	Property Tax	-	-	-	-	-	-	-	-	-	-	-	-	-	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	55,475	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121	143,121
	Debt Return - Capital Asset	-	-	17,893	53,638	89,872	126,587	163,215	201,921	242,697	283,369	323,941	364,415	424,212	483,657	532,417	590,150	648,430	707,250	765,929	824,723	883,633	942,401	1,001,027	1,059,511	1,132,992	1,206,145	1,270,071	1,340,082	1,410,311	1,480,756	1,551,031	1,621,287	1,691,524	1,761,590	1,831,486	1,901,213	1,992,298
	Debt Return - Deferred Balance	91	446	1,108	2,039	3,248	4,740	6,523	8,619	11,243	14,580	18,425	22,653	27,116	31,907	37,238	43,028	49,288	56,025	63,243	70,945	79,174	88,264	98,178	108,633	119,496	130,866	142,920	155,566	168,812	182,663	197,332	213,116	229,810	247,127	265,069	283,701
	Equity Return - Capital Asset	-	-	54,913	164,616	275,815	388,496	500,905	619,695	744,836	869,657	994,174	1,118,387	1,301,905	1,484,343	1,633,985	1,811,170	1,990,030	2,170,547	2,350,632	2,531,073	2,711,866	2,892,224	3,072,147	3,251,635	3,477,147	3,701,655	3,897,842	4,112,706	4,328,240	4,544,435	4,760,110	4,975,726	5,191,280	5,406,313	5,620,826	5,834,817	6,114,355
	Equity Return - Deferred Balance	-	279	1,368	3,400	6,259	9,968	14,548	20,020	26,451	34,506	44,745	56,546	69,521	83,219	97,922	114,282	132,052	151,264	171,941	194,093	217,731	242,986	270,881	301,308	333,393	366,733	401,627	438,621	477,433	518,083	560,591	605,612	654,053	705,286	758,431	813,496	870,677
		-	130,208	379,185	570,861	765,618	968,647	1,172,469	1,385,936	1,620,460	2,145,727	2,641,235	2,875,859	3,190,669	3,213,540	3,660,455	3,988,133	4,319,903	4,661,954	5,005,376	5,351,223	5,700,031	6,107,211	6,934,616	7,290,694	7,709,992	7,877,408	8,436,277	8,859,480	9,285,982	9,719,283	10,154,359	10,893,985	11,753,298	12,199,395	12,647,336	13,097,132	13,636,638

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DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT
2018 Test Year O&M

2018 O&M is a part of the rate case test period O&M. Therefore the amount elegible for deferral would be the O&M incurred above the amount included in the 2018 test period.

2018 O&M incurred	**2018**		**NC Retail**
Self Optimizing Grid	113,457	0.762817	86,547
Targeted Undergrounding	103,146	0.762817	78,682
Hardening & Resiliency	2,939	0.762817	2,242
Customer Delivery Hardening & Resiliency	9,513	0.762817	7,257
Enterprise Applications	4,596,836	0.747926	3,438,093
Advanced DMS	851,514	0.747926	636,869
Communications	864,296	0.747926	646,429
Transmission	-		-
Total	6,541,701		4,896,119

Distribution	174,727
Transmission	-
General	4,721,392

DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT
Capital Spend and Installation O&M Estimates
Dollars in Millions

Calculation of NC Retail Costs

DEC Total Capital Spend				
Strategic Category [1]	**2020**	**2021**	**2022**	**5-year Total**
Advanced DMS	$ 12	$ 12	$ 15	$ 40
AMI	$ -	$ -	$ -	-
Communication	$ 36	$ 48	$ 55	139
Enterprise Applications	$ 12	$ 10	$ 15	37
Hardening/Resiliency	$ 47	$ 26	$ 79	152
Self Optimizing Grid	$ 156	$ 290	$ 333	779
Targeted Underground	$ 14	$ 20	$ 45	79
Distributed Energy	$ 4	$ 1	$ 1	6
Transmission	$ 161	$ 174	$ 159	494
Other	$ -	$ -	$ -	-
				-
Total P/F Capital	**$ 443**	**$ 580**	**$ 703**	**$ 1,726**

DEC Total Installation O&M Spend				
Strategic Category [1]	**2020**	**2021**	**2022**	**5-year Total**
Advanced DMS	$ 1	$ 1	$ 2	$ 4
AMI	-	-	-	-
Communication	2	3	4	9
Enterprise Applications	5	4	6	15
Hardening/Resiliency	2	1	3	5
Self Optimizing Grid	2	4	5	11
Targeted Underground	0	0	0	1
Distributed Energy	0	0	0	0
Transmission	2	2	2	5
Other	-	-	-	-
				-
Total O&M	**$ 14**	**$ 15**	**$ 21**	**$ 50**

DEC Total Capital Spend					NC Retail
SYSTEM	**2020**	**2021**	**2022**	**3-year Total**	**Allocation [2]**
ADMS	12.5	11.8	15.4	39.6	74.79%
Communication	36.1	48.0	54.7	138.7	74.79%
Enterprise Appliaction	12.0	9.9	15.2	37.1	74.79%
Distributed Energy	4.0	0.5	1.0	5.5	74.79%
Distribution NC	158.5	278.1	360.2	796.9	Direct
Distribution SC	56.5	62.5	83.1	202.2	
Transmission	163.2	169.6	173.4	506.2	52.66%
TOTAL	442.8	580.4	703.0	1,726.2	

DEC Total Installation O&M Spend					NC Retail
SYSTEM	**2020**	**2021**	**2022**	**3-year Total**	**Allocation [2]**
ADMS	1.3	1.2	1.6	4.1	74.79%
Communication	2.4	3.2	3.6	9.2	74.79%
Enterprise Appliaction	4.9	4.1	6.2	15.2	74.79%
Distributed Energy	0.3	0.1	0.1	0.5	74.79%
Distribution NC	2.8	4.0	6.1	12.9	Direct
Distribution SC	1.0	1.0	1.5	3.5	
Transmission	1.6	1.7	1.6	4.9	52.66%
TOTAL	14.4	15.3	20.7	50.3	

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DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT
Capital Spend and Installation O&M Estimates
Dollars in Millions

Calculation of NC Retail Costs

DEC NC Retail Capital Spend				
DEC NC Retail	**2020**	**2021**	**2022**	**3-year Total**
ADMS	9.3	8.8	11.5	29.6
Communication	27.0	35.9	40.9	103.8
Enterprise Appliaction	9.0	7.4	11.3	27.8
Distributed Energy	3.0	0.4	0.8	4.1
Distribution NC	158.5	278.1	360.2	796.9
Distribution SC				-
Transmission	86.0	89.3	91.3	266.6
TOTAL	292.8	419.9	516.0	1,228.7

DEC NC Retail Installation O&M Spend				
DEC NC Retail	**2020**	**2021**	**2022**	**3-year Total**
ADMS	1.0	0.9	1.2	3.1
Communication	1.8	2.4	2.7	6.9
Enterprise Appliaction	3.7	3.0	4.6	11.4
Distributed Energy	0.2	0.0	0.1	0.3
Distribution NC	2.8	4.0	6.1	12.9
Distribution SC				-
Transmission	0.8	0.9	0.8	2.6
TOTAL	10.3	11.3	15.5	37.2

Plant in Service Assumptions [1]	
Distribution	1 month
Transmission	6 months
Communication	3 months
Advanced DMS & Enterprise Application	Annually in December

[1] System numbers and Plant in Service assumptions from Witness Oliver
[2] Allocation factors from the Cost of service study.

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DUKE ENERGY CAROLINAS, LLC
North CAROLINA RETAIL GRID IMPROVEMENT

Mcmaneus
Calculation of NC Retail Costs

Weighted Average Cost of Capital based on docket E-7 Sub 1146

Line No.	Description	Capital Structure	Cost/ Return	Weighted Cost/Return	Income Taxes Factor	After Tax Return	Income Taxes Factor	Revenue Requirement Excluding Gross Reciept Tax and Regulatory Fee	Combined Gross Receipts Tax and Regulatory Fee Factor	Revenue Requirement Including Gross Reciept Tax and Regulatory Fee
1		(a)	(b)	(c)						
2										
3	Long-term debt	48.0000% [1]	4.56% [2]	2.1884%	0.7664970	1.67742%	1.00000	2.18843%	99.62023%	2.19677%
4	Members' equity	52.0000% [1]	9.90% [2]	5.1480%	1.0000000	5.14800%	0.76650	6.71627%	99.62023%	6.74187%
5	Total (L3 + L4)	100.0000%		7.3364%		6.8254%		8.9047%		8.9386%
6										
7	Gross revenue				1.0000000					
8	State income tax rate (L36)				0.0297500					
9	Remainder (L14 - L15)				0.9702500					
10	Federal income tax rate				0.2100000					
11	Federal income tax (L16 x L17)				0.2037525					
12	State income tax rate (L36)				0.0297500					
13	Combined income tax rate (L18 + L19)				0.2335030					
14	1 minus combined income tax rate (1 - L20)				0.7664970					
15										
	Gross revenue				1.0000000					
	uncollectibles rate				0.0025010					
	Balance				0.9974990					
	Regulatory fee rate				0.0012967					
	Combined gross receipts tax and regulatory fee rate (L23 - L24 - L25)				0.9962023					
	State income tax (L15 x L26)				0.0296370					
	Balance (L26 - L27)				0.9665653					
	Federal income tax (L17 x L28)				0.2029787					
	Retention factor (L28 - L29)				0.7635866					
	State income tax rate									
	NC	0.0250000	67%	0.0167500						
	SC	0.0500000	26%	0.0130000						
				0.0297500						
					0.2364134					

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DUKE ENERGY CAROLINAS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS AS OF DECEMBER 31, 2018
VERSION 1 - REVISED

			CURRENT					PROPOSED					
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(7)	(7)	(8)	(9)	(10)	(11)	(9)=(8)/(5)	(13)
	TRANSMISSION PLANT												
352.00	STRUCTURES AND IMPROVEMENTS	108,489,173.06		60-R3	(20)	2,115,539	1.95		55-R2	(10)	2,170,087	2.00	54,548
353.00	STATION EQUIPMENT	1,849,287,080.50		52-R1.5	(25)	39,204,886	2.12		48-R1.5	(20)	43,512,066	2.35	4,307,180
354.00	TOWERS AND FIXTURES	587,791,762.36		70-R2	(40)	9,933,681	1.69		75-R2	(50)	10,058,236	1.71	124,555
355.00	POLES AND FIXTURES	558,831,171.11		50-R1.5	(25)	12,741,351	2.28		48-R1	(30)	15,024,969	2.69	2,283,618
356.00	OVERHEAD CONDUCTORS AND DEVICES	760,660,328.73		60-R2	(40)	15,213,207	2.00		60-R2.5	(40)	15,381,796	2.02	168,589
357.00	UNDERGROUND CONDUIT	124,173.82		55-S4	0	1,391	1.12		55-S4	0	1,356	1.09	(35)
358.00	UNDERGROUND CONDUCTOR AND DEVICES	5,812,002.49		55-S3	0	80,787	1.39		50-S4	0	104,142	1.79	23,355
359.00	ROADS AND TRAILS	42,238.00		65-R4	0	617	1.46		65-R4	0	615	1.46	(2)
	TOTAL TRANSMISSION PLANT	**3,871,037,930.07**				**79,291,459**	**2.05**				**86,253,267**	**2.23**	**6,961,808**
	DISTRIBUTION PLANT												
361.00	STRUCTURES AND IMPROVEMENTS	112,827,983.33		60-R2.5	(20)	2,188,863	1.94		55-S0.5	(10)	2,214,720	1.96	25,857
362.00	STATION EQUIPMENT	1,376,647,876.87		42-R1	(25)	35,655,180	2.59		44-R1	(20)	32,261,405	2.34	(3,393,775)
364.00	POLES, TOWERS AND FIXTURES	1,633,135,516.15		49-R2	(25)	32,336,083	1.98		50-R2	(30)	34,614,100	2.12	2,278,017
365.00	OVERHEAD CONDUCTORS AND DEVICES	2,263,640,318.34		49-R0.5	(20)	43,914,622	1.94		52-R0.5	(25)	44,559,335	1.97	644,713
366.00	UNDERGROUND CONDUIT	203,949,849.78		55-R3	(15)	3,202,013	1.57		60-R3	(15)	2,791,873	1.37	(410,140)
367.00	UNDERGROUND CONDUCTORS AND DEVICES	2,040,861,815.64		54-R3	(20)	40,817,236	2.00		55-R3	(20)	40,019,115	1.96	(798,121)
368.00	LINE TRANSFORMERS	1,518,704,424.45		43-R1.5	0	26,881,068	1.77		45-R1.5	(10)	31,289,615	2.06	4,408,547
369.00	SERVICES	1,107,500,564.10		50-R1.5	(10)	14,619,007	1.32		52-R1.5	(15)	15,374,051	1.39	755,044
370.00	METERING EQUIPMENT	100,494,301.47		20-L0	0	5,326,198	5.30		17-L0	0	2,615,173	2.60	(2,711,025)
370.01	METERS	68,544,544.14	12-2019	20-L0	* 0	10,553,102			17-L0	0	10,601,895	**	48,793
370.02	METERS -UTILITY OF THE FUTURE	438,309,266.89		15-S2.5	0	31,514,436	7.19		15-S2.5	0	30,148,683	6.88	(1,365,753)
371.00	INSTALLATIONS ON CUSTOMERS' PREMISES	914,011,910.46		40-R0.5	(5)	19,742,657	2.16		40-R1	(5)	21,338,273	2.33	1,595,616
373.00	STREET LIGHTING AND SIGNAL SYSTEMS	243,393,601.32		35-R1	(10)	6,522,949	2.68		36-R0.5	(10)	6,020,417	2.47	(502,532)
	TOTAL DISTRIBUTION PLANT	**12,022,021,972.94**				**273,273,414**	**2.27**				**273,848,655**	**2.28**	**575,241**
	Excluding Meters	11,414,673,860				225,879,678	**1.98**				230,482,904	**2.02**	
	GENERAL PLANT												
390.00	STRUCTURES AND IMPROVEMENTS	675,049,911.19		40-R2	(10)	21,736,607	3.22		40-S1	(10)	20,657,294	3.06	(1,079,313)
391.00	OFFICE FURNITURE AND EQUIPMENT	48,878,029.08		15-SQ	0	3,260,165	6.67		15-SQ	0	3,258,543	6.67	(1,622)
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP	113,710,527.80		8-SQ	0	14,213,816	12.50		8-SQ	0	14,217,928	12.50	4,112
392.00	TRANSPORTATION EQUIPMENT												
	PASSENGER CARS AND STATION WAGONS	94,914.61		5-S2.5	5	0	-		5-S2.5	10	3,477	3.66	3,477
	LIGHT TRUCKS	2,419,475.49		6-L3	5	181,461	7.50		6-L3	10	150,280	6.21	(31,181)
	MEDIUM TRUCKS	438,550.50		8-L2	5	0	-		8-L2	10	32,054	7.31	32,054
	HEAVY TRUCKS	1,304,835.00		10-L2	5	129,440	9.92		10-L2	10	0	-	(129,440)
	HEAVY TRUCKS / POWER EQUIPPED	2,801,236.11		10-L2	5	0	-		10-L2	10	0	-	0
	TRACTORS	65,897.00		13-L3	5	6,847	10.39		13-L3	10	0	-	(6,847)
	TRAILERS	5,511,868.72		17-L0.5	5	288,271	5.23		16-L0.5	10	104,821	1.90	(183,450)
	TOTAL TRANSPORTATION EQUIPMENT	12,636,777.43				606,019	4.80				290,632	2.30	(315,387)
393.00	STORES EQUIPMENT	14,298,928.76		20-SQ	0	714,946	5.00		20-SQ	0	714,946	5.00	0
394.00	TOOLS,SHOPS AND GARAGE EQUIPMENT												
	FULLY ACCRUED	0.00		0.00	0	0	-				0	-	0
	AMORTIZED	104,793,595.68		20-SQ	0	5,239,680	5.00		20-SQ	0	5,240,529	5.00	849
	TOTAL TOOLS SHOP AND GARAGE EQUIPMENT	104,793,595.68				5,239,680					5,240,529		849
395.00	LABORATORY EQUIPMENT	5,877,459.28		15-SQ	0	392,027	6.67		15-SQ	0	391,830	6.67	(197)
396.00	POWER OPERATED EQUIPMENT												
	MOBILE CRANES	509,129.42		19-S1.5	0	15,987	3.14		19-S1.5	10	19,910	3.91	3,923
	MISCELLANEOUS NON-HIGHWAY EQUIPMENT	1,020,976.03		14-S1.5	0	48,394	4.74		13-L2	10	0	-	(48,394)
	MISCELLANEOUS EQUIPMENT	9,797,880.43		14-S1.5	0	640,781	6.54		13-L2	10	0	-	(640,781)
	TOTAL POWER OPERATED EQUIPMENT	11,327,985.88				705,162	6.22				19,910	0.18	(685,252)
397.00	COMMUNICATION EQUIPMENT	153,219,179.05		10-SQ	0	15,321,918	10.00		10-SQ	0	15,328,598	10.00	6,680
398.00	MISCELLANEOUS EQUIPMENT	10,275,692.04		20-SQ	0	513,785	5.00		20-SQ	0	513,784	5.00	(1)
	TOTAL GENERAL PLANT	**1,150,068,086.19**				**62,704,125**	**5.45**				**60,633,994**	**5.27**	**(2,070,131)**
	DEPRECIABLE LAND RIGHTS												

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DUKE ENERGY CAROLINAS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS AS OF DECEMBER 31, 2018
VERSION 1 - REVISED

	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	CURRENT PROBABLE RETIREMENT DATE	CURRENT SURVIVOR CURVE	CURRENT NET SALVAGE PERCENT	CURRENT CALCULATED ANNUAL ACCRUAL AMOUNT	CURRENT CALCULATED ANNUAL ACCRUAL RATE	PROPOSED PROBABLE RETIREMENT DATE	PROPOSED SURVIVOR CURVE		PROPOSED NET SALVAGE PERCENT	PROPOSED CALCULATED ANNUAL ACCRUAL AMOUNT	PROPOSED CALCULATED ANNUAL ACCRUAL RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(7)	(7)	(8)	(9)		(10)	(11)	(9)=(8)/(5)	(13)
310.00	RIGHTS OF WAY													
	MARSHALL	452,636.00	06-2034	100-R4	0	0	-	06-2034	100-R4	*	0	0	-	0
	BELEWS CREEK	1,543,811.00	06-2037	100-R4	0	0	-	06-2037	100-R4	*	0	0	-	0
	LEE	3,106.00	06-2030	100-R4	0	0	-	06-2030	100-R4	*	0	0	-	0
	ALLEN	4,303.00	06-2026	100-R4	0	0	-	06-2024	100-R4	*	0	0	-	0
	TOTAL ACCOUNT 310	2,003,856.00				0	-					0	-	0
320.00	RIGHTS OF WAY													
	OCONEE	425,003.00	07-2034	100-R4	0	6,588	1.55	07-2034	100-R4	*	0	6,546	1.54	(42)
	MCGUIRE	74,882.00	03-2043	100-R4	0	1,236	1.65	03-2043	100-R4	*	0	1,227	1.64	(9)
	CATAWBA	456,656.68	12-2043	100-R4	0	8,448	1.85	12-2043	100-R4	*	0	8,399	1.84	(49)
	TOTAL ACCOUNT 320	956,541.68				16,272	1.70					16,172	1.69	(100)
330.00	RIGHTS OF WAY													
	COWANS FORD	6,881,547.00	06-2055	110-R4	0	45,418	0.66	06-2055	110-R4	*	0	45,372	0.66	(46)
	BAD CREEK	723,692.00	06-2058	110-R4	0	8,901	1.23	06-2058	110-R4	*	0	8,840	1.22	(61)
	JOCASSEE	436,179.00	06-2046	110-R4	0	3,751	0.86	06-2046	110-R4	*	0	3,685	0.84	(66)
	KEOWEE	12,071,075.00	06-2046	110-R4	0	86,912	0.72	06-2046	110-R4	*	0	86,162	0.71	(750)
	FISHING CREEK	35,796.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	BRIDGEWATER	393,705.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	GASTON SHOALS	16,648.00	06-2036	110-R4	0	0	-	06-2036	110-R4	*	0	0	-	0
	LOOKOUT SHOALS	7,426.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	MOUNTAIN ISLAND	323,913.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	99 ISLANDS	17,102.00	06-2036	110-R4	0	0	-	06-2036	110-R4	*	0	0	-	0
	OXFORD	695,790.00	06-2055	110-R4	0	417	0.06	06-2055	110-R4	*	0	548	0.08	131
	RHODHISS	199,929.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	17	0.01	17
	TUXEDO	245,404.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	WATEREE	204,111.00	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	WYLIE	1,189,441.24	06-2055	110-R4	0	0	-	06-2055	110-R4	*	0	0	-	0
	NPL BEAR CREEK	435.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	NPL FRANKLIN	12,423.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	NPL NANTAHALA	80,304.00	06-2042	110-R4	0	0	-	06-2042	110-R4	*	0	0	-	0
	NPL QUEENS CREEK	5,782.00	06-2032	110-R4	0	0	-	06-2032	110-R4	*	0	0	-	0
	NPL TENNESSEE CREEK	711.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	NPL THORPE	47,127.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	NPL TUCKASEGEE	1,518.00	06-2041	110-R4	0	0	-	06-2041	110-R4	*	0	0	-	0
	TOTAL ACCOUNT 330	23,590,058.24				145,399	0.62					144,624	0.61	(775)
340.00	RIGHTS OF WAY													
	DAN RIVER	7,693.00	06-2052	60-R4	0	342	4.45	06-2052	60-R4	*	0	383	4.98	41
	TOTAL ACCOUNT 330	7,693.00				342	4.45					383	4.98	41
350.00	RIGHTS OF WAY	163,057,492.39		75-R4	0	1,875,161	1.15		80-R4		0	1,673,327	1.03	(201,834)
360.00	RIGHTS OF WAY	8,830,280.42		75-R3	0	120,975	1.37		80-R3		0	110,290	1.25	(10,685)
360.20	LAND RIGHTS	561,560.00		75-R3	0	8,480	1.51		80-R3		0	7,656	1.36	(824)
389.00	RIGHTS OF WAY	550,127.03		60-R3	0	8,307	1.51		60-R3		0	8,256	1.50	(51)
389.20	LAND RIGHTS	165.00		60-R3	0	2	1.21		60-R3		0	2	1.21	0
	TOTAL DEPRECIABLE LAND RIGHTS	**199,557,773.76**				**2,174,938**	**1.09**					**1,960,710**	**0.98**	**(214,228)**
	RESERVE ADJUSTMENT FOR AMORTIZATION													
391.00	OFFICE FURNITURE AND EQUIPMENT					(485,779) ***						(1,091,336) ***		(605,557)
391.10	OFFICE FURNITURE AND EQUIPMENT - EDP					(7,162,540) ***						(6,686,253) ***		476,287
393.00	STORES EQUIPMENT					(167,822) ***						(510,479) ***		(342,657)
394.00	TOOLS,SHOP AND GARAGE EQUIPMENT					791,555 ***						182,044 ***		(609,511)
395.00	LABORATORY EQUIPMENT					60,273 ***						(196,882) ***		(257,155)
397.00	COMMUNICATION EQUIPMENT					(3,375,963) ***						(5,756,654) ***		(2,380,691)
398.00	MISCELLANEOUS EQUIPMENT					181,040 ***						152,142 ***		(28,898)
	TOTAL RESERVE ADJUSTMENT FOR AMORTIZATION					**(10,159,236)**						**(13,907,418)**		**(3,748,182)**
	TOTAL DEPRECIABLE PLANT	**50,816,367,931.52**				**1,343,742,881**	**2.64**					**1,458,084,379**	**2.87**	**109,738,272**
	NONDEPRECIABLE PLANT													

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DUKE ENERGY CAROLINAS
COMPARISON OF CURRENT AND PROPOSED DEPRECIATION PARAMETERS, RATES AND ACCRUALS AS OF DECEMBER 31, 2018
VERSION 1 - REVISED

			CURRENT					PROPOSED					
	ACCOUNT	ORIGINAL COST AS OF DECEMBER 31, 2018	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	PROBABLE RETIREMENT DATE	SURVIVOR CURVE	NET SALVAGE PERCENT	CALCULATED ANNUAL ACCRUAL AMOUNT	CALCULATED ANNUAL ACCRUAL RATE	INCREASE/ DECREASE
	(1)	(2)	(3)	(4)	(5)	(6)=(2)*(7)	(7)	(8)	(9)	(10)	(11)	(9)=(8)/(5)	(13)
302.00	FRANCHISES AND CONSENTS	10,582,513.97											
302.01	NPL FEASIBILITY	51,514.00											
303.00	MISCELLANEOUS INTANGIBLE PLANT	881,801,467.56											
303.10	MISCELLANEOUS INTANGIBLE PLANT - 10 YEAR	77,334,560.26											
303.02	NUCLEAR LICENSING	16,980,814.09											
310.00	LAND	26,928,990.69											
317.00	ARO	886,954,100.65											
320.00	LAND	2,084,901.52											
326.00	ARO	(333,080,604.95)											
330.00	LAND	28,756,791.34											
340.00	LAND	9,356,078.64											
347.00	ARO	14,776,081.47											
350.00	LAND	33,315,866.21											
360.00	LAND	54,389,762.82											
389.00	LAND	62,366,844.64											
399.00	ARO	(931,335.11)											
	TOTAL NONDEPRECIABLE PLANT	**1,771,668,347.80**											
	ACCOUNTS NOT STUDIED												
352.99	STRUCTURES AND IMPROVEMENTS - IMPAIRMENT	(4,692,470.50)											
353.99	STATION EQUIPMENT - IMPAIRMENT	(9,531,580.93)											
354.99	TOWERS AND FIXTURES - IMPAIRMENT	(146,639.71)											
355.99	POLES AND FIXTURES - IMPAIRMENT	(146,639.63)											
356.99	OVERHEAD CONDUCTORS AND DEVICES - IMPAIRMENT	(146,639.68)											
	TOTAL ACCOUNTS NOT STUDIED	**(14,663,970.45)**											
	TOTAL ELECTRIC PLANT	**52,573,372,308.87**				**1,343,742,881**					**1,458,084,379**		**109,738,272**

* Curve shown is interim survivor curve. Each facility in the account is assigned an individual probable retirement year.
** Annual Accrual Amount calculated based on remaining amortization period of 14.58 years (August 2033 which is 15 years from implementation).
*** 5 year Amortization of Adjusted Reserve related to implementation of Amortization Accounting.

= Provided in Melissa A.'s 5-2-2019 email

= Used the Ordered Projected Rates from 2016 Depr Study.

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
Annualize retail revenues for current rates
For the test period ended December 31, 2018

2018 Calculation of Tax Rates

Current (Statutory) Tax Rate Per "Provision" - Year 2019

Line No.	Description	Total	Statutory Rate (a)	Allocation Factor (b)	Composite Rate (a) x (b)
1					
2		100.0000%			
3	North Carolina	1.6750%	2.50%	67.0000%	1.67500%
4	South Carolina	1.3000%	5.00%	26.0000%	1.30000%
5	Federal Taxable Income (L2 - L3 - L4)	97.0250%			
6	Federal Tax Rate	**21.0000%**			
7	Federal Net of State (L5 x L6)	20.3753%			
8	North Carolina (L3)	1.6750%			
9	South Carolina (L4)	1.3000%			
10	Composite Tax Rate (L7 + L8 + L9)	23.3503%			

Source: Duke Energy Carolinas Tax Department

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
Annualize property taxes on year end plant balances
For the test period ended December 31, 2018
(Dollars in thousands)

Line No.	Description	State - NC		State - SC			
1	12/31/2017 System Balances Subject to Property Tax						
2	Utility Plant (101-106, 114)	$ 38,269,626	[1]	$ 38,269,626	[1]		
3	Less: Asset Retirement Obligations	(198,027)	[2]	(198,027)	[2]		
4	Construction Work in Progress (107)	2,610,346	[1]	-	[3]		
5	Net Nuclear Fuel (120.1-5)	842,653	[1]	-	[3]		
6	Fuel Stock (151)	229,301	[1]	-	[3]		
7	Materials & Supplies (154)	474,672	[4]	222,870	[4]		
8	Store Expenses Undistributed (163) [M & S Burdens]	24,528	[4]	19,892	[4]		
9	Other Materials & Supplies (156)	66	[4]	5	[4]		
10	Property Subject to Property Tax (Sum L2 through L8)	$ 42,253,166		$ 38,314,366			
11							
12	2018 Property Tax Expense Paid	$ 90,787	[5]	$ 117,894	[6]	Combined	
13	Average Property Tax Rate (L12 / L10)	0.21486%		0.30770%			0.259%
14							
15	12/31/2018 System Balances Subject to Property Tax						
16	Utility Plant (101-106, 114)	$ 41,161,863	[1]	$ 41,161,863	[1]		
17	Less: Asset Retirement Obligations	(567,718)	[2]	(567,718)	[2]		
18	Construction Work in Progress (107)	1,632,658	[1]	-	[3]		
19	Net Nuclear Fuel (120.1-5)	814,296	[1]	-	[3]		
20	Fuel Stock (151)	220,761	[1]	-	[3]		
21	Plant Materials & Operating Supplies (154)	464,250	[7]	217,976	[7]		
22	Store Expenses Undistributed (163) [M & S Burdens]	24,952	[7]	20,236	[7]		
23	Other Materials & Supplies (156)	96	[7]	8	[7]		
24	Property Subject to Property Tax (Sum L16 through L22)	$ 43,751,062		$ 40,832,357			
25							
26	Average Property Tax Rate (L13)	0.21486%		0.30770%			
27	Annualized Property Tax Expense (L24 x L26)	$ 94,005		$ 125,641			
28							
29	Test Year Property Tax Expense (Excluding Deferrals) (L12)	$ 90,787		$ 117,894			
30	Property Tax Expense Adjustment (L27 - L29)	$ 3,218		$ 7,748			
31							
32	Total Property Tax Adjustment (NC Col. L30 + SC Col. L30)	$ 10,966					
33	Allocation Factor - Gross Plant	68.3083%	[8]				
34	Impact to general taxes (L32 x L33)	$ 7,491					
35	Statutory tax rate	23.3503%	[9]				
36	Impact to income taxes (-L34 x L35)	$ (1,749)					
37	Impact to operating income (-L34 - L36)	$ (5,742)					

[1] NC-0902 - FERC Form 1, Comparative Balance Sheet, Page 110, Lines 2, 3, 13, and 45
[2] NC-0903 - Asset Retirement Obligations
[3] There is no property tax applied for these items in SC - Per DEC Property Tax Department
[4] NC-0904 - Duke Energy Carolinas - Materials and Supplies - By State, Line 16, Line 17 and Line 18
[5] NC-0905 - 2018 - Property Tax Expense - NC, Col. (b) + Col. (c)
[6] NC-0906 - 2018 - Property Tax Expense - SC, Col. (a)
[7] 2018 FERC 154, 156 and 163 accounts are spread across NC and SC based on 2017 distribution.
[8] COSS NC retail percentage of gross plant in service
[9] NC-0104 - 2019 Calculation of Tax Rates - Statutory Tax Rate, Line 10

Alvarez Exhibit-3

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Feb 25 2020

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 11, 2020

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 8-24, 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

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Feb 25 2020

NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-24
Page 1 of 1

Request:

8-24. Refer to DEC's targeted undergrounding program generally.
a. How many miles of residential "Backyard" overhead lines does DEC estimate it has today?
b. What percentage of the miles DEC proposes to underground in its proposed targeted undergrounding program are shared with telecom, internet, or cable TV providers?

Response:

a) The amount is not quantifiable using GIS attributes
b) We have assumed all, although there will be exceptions

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Feb 25 2020

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

Docket No. E-2, Sub 1219

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. 5-22, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Feb 25 2020

NCJC
Data Request No. 5
DEP Docket No. E-2, Sub 1219
Item No. 5-22

Request:

5-22. Refer to DEP's targeted undergrounding program generally.
a. How many miles of residential "Backyard" overhead lines does DEP estimate it has today?
b. What percentage of the miles DEC proposes to underground in its proposed targeted undergrounding program are shared with telecom, internet, or cable TV providers?

Response:

a) The amount is not quantifiable using GIS attributes
b) We have assumed all, although there will be exceptions

Alvarez Exhibit - 4

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Feb 25 2020

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**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 8-1, 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

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Feb 25 2020

NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-1

Request:

8-1. Refer to forthcoming responses from DEC for NCJC DRs 6-08 and 6-09.
a. How many miles of 44kV does DEC have today?
b. How many miles of 44kV upgrades will deliver a capacity increase, and to what capacity?
c. How many distribution circuits does DEC have? DEP?

Response:

a. Approximately 2,800 miles
b. In the 3-year Grid Improvement Plan there are no capacity increase projects associated with the 44kV rebuilds. 44kV line rebuilds in the 3-year plan total approximately 80 miles and are all driven by reliability improvements, these rebuilds will reduce the probability of circuit failures that could result in customer outages. This work is all part of Phase I as described in Oliver Exhibit 4 page 36. These 44kV circuits are rebuilt to 100kV standards with regards to structure design, insulation level, and conductor sizing. There is no timeline established for Phase II, voltage conversions to 100kV, which would deliver the capacity increase.
c. DEC NC has 2,093 circuits as of November 2019.
DEP NC has 1,077 circuits as of November 2019.

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

Docket No. E-2, Sub 1219

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

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 5-1, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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NCJC
Data Request No. 5
DEP Docket No. E-2, Sub 1219
Item No. 5-1

Request:

5-1. Refer to forthcoming responses from DEC for NCJC DRs 6-08 and 6-09.
a. How many miles of 44kV does DEP have today?
b. How many miles of 44kV will be upgraded, and to what capacity, in DEP if the current GIP is approved?

Response:

a. 0 miles. Voltages in the DEP Transmission system are 230kV, 115kV, and 69kV.
b. N/A

Alvarez Exhibit - 5

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

Docket No. E-7, Sub 1214

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

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☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 8-26, 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

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Feb 25 2020

NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-26

Request:

8-26. Refer to DEC's response to NCJC DR 5-49, which states "in the past 5 years in the DEC system there have been 88,739 customer outages totaling 18,442,020 customer minutes interrupted as a result of transformer equipment failures."
a. How many individual distribution transformer failures are represented in these statistics?
b. How many distribution transformers does DEC have?
c. How many individual transmission transformer failures are represented in these statistics?
d. How many transmission transformers does DEC have?

Response:

Note, in answering the question Duke Energy assumed it related to substation transformer banks. "Distribution" would be T to D banks and "Transmission" would be T to T banks. Upon re-running the query from the Transmission Reliability Reporting System it was identified that the original numbers provided in DR 5-49 were incorrect and lower than actual. Updated numbers applicable to DR 5-49: in the past 5 years in the DEC system there have been 157,682 customer outages totaling 36,134,492 customer minutes interrupted as a result of transformer equipment failures. The below responses are associated with these updated numbers.
a. Individual transformer assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 57 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 35 of these events are associated with distribution class transformers.
b. DEC has approximately 4,500 distribution class substation transformers
c. Individual transformer assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 57 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 22 of these events are associated with transmission class transformers.
d. DEC has approximately 400 transmission class substation transformers

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Feb 25 2020

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

Docket No. E-2, Sub 1219

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

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The attached response to NCJC Data Request No. 5-17, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Request:

5-17. Refer to DEP's response to NCJC DEP DR 2-16(c), which states "in the past 5 years in the DEP system there have been 290,450 customer outages totaling 28,539,477 customer minutes interrupted as a result of transformer equipment failures."
a. How many individual distribution transformer failures are represented in these statistics?
b. How many distribution transformers does DEP have?
c. How many individual transmission transformer failures are represented in these statistics?
d. How many of transmission transformers does DEP have?

Response:

For this response, it is assumed that "distribution transformer" refers to a substation T to D bank, and "transmission transformer" refers to a substation T to T bank.
a. Individual transformer assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 65 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 56 of these events are associated with distribution class transformers.
b. DEP has approximately 900 distribution class substation transformers
c. Individual transformer assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 65 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 9 of these events are associated with transmission class transformers.
d. DEP has approximately 117 transmission class substation transformers

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Feb 25 2020

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 11, 2020

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The attached response to NCJC Data Request No. 8-25, 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

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Feb 25 2020

NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-25

Request:

8-25. Refer to DEC's response to NCJC DR 5-44, which states "in the past 5 years in the DEC system there have been 77,515 customer outages totaling 8,642,573 customer minutes interrupted as a result of breaker equipment failures."
a. How many individual distribution breaker failures are represented in these statistics?
b. How many distribution breakers does DEC have?
c. How many of DEC's distribution breakers are oil filled?
d. How many individual transmission breaker failures are represented in these statistics?
e. How many transmission breakers does DEC have?
f. How many of DEC's transmission breakers are oil filled?

Response:

Upon re-running the query from the Transmission Reliability Reporting System it was identified that the original numbers provided in DR 5-44 were incorrect and lower than actual. Updated numbers applicable to DR 5-44: in the past 5 years in the DEC system there have been 123,103 customer outages totaling 11,242,664 customer minutes interrupted as a result of breaker equipment failures. The below responses are associated with these updated numbers.
a. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 50 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 37 of these events are associated with distribution class breakers.
b. DEC has approximately 4,600 distribution class substation breakers
c. DEC has approximately 1,500 distribution class substation oil breakers
d. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 50 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 13 of these events are associated with transmission class breakers.
e. DEC has approximately 3,400 transmission class substation breakers
f. DEC has approximately 2,000 transmission class substation oil breakers

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

Docket No. E-2, Sub 1219

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

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The attached response to NCJC Data Request No. 5-16, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Feb 25 2020

NCJC
Data Request No. 5
DEP Docket No. E-2, Sub 1219
Item No. 5-16

Request:

5-16. Refer to DEP's response to NCJC DEP DR 2-15 (g), which states "in the past 5 years in the DEP system there have been 46,085 customer outages totaling 2,549,341 customer minutes interrupted as a result of breaker equipment failures."
a. How many individual distribution breaker failures are represented in these statistics?
b. How many of these distribution breakers were oil-filled?
c. How many distribution breakers does DEP have?
d. How many oil-filled distribution breakers does DEP have?
e. How many individual transmission breaker failures are represented in these statistics?
f. How many of these transmission breakers were oil filled?
g. How many transmission breakers does DEP have?
h. How many oil-filled transmission breakers does DEP have?

Response:

a. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 8 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 5 of these events are associated with distribution class breakers.
b. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, therefore it is unknown how many of these breakers were oil-filled.
c. DEP has approximately 1,700 distribution class substation breakers
d. DEP has approximately 800 distribution class substation oil breakers
e. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 8 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted. 3 of these events are associated with transmission class breakers.
f. Individual breaker assets are not tracked to specific outages in the Transmission Reliability Reporting System, therefore it is unknown how many of these breakers were oil-filled.
g. DEP has approximately 940 transmission class substation breakers
h. DEP has approximately 350 transmission class substation oil breakers

Alvarez Exhibit - 7

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Feb 25 2020

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

Docket No. E-7, Sub 1214

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

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The attached response to NCJC Data Request No. 2-5, 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

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Feb 25 2020

NCJC
Data Request No. 2
DEC Docket No. E-7, Sub1214
Item No. 2-5

Request:

2-5. Please refer to DEC's responses to NCSEA DR 2-19, which indicates that the physical security of substations will be upgraded at a rate of 11-13 per year.
a. How many substations does DEC have in North Carolina?
b. Which ones will be upgraded in the proposed 3-year Grid Improvement Plan period?
c. How many substations does DEP have in North Carolina?
d. Which ones will be upgraded in the proposed 3-year Grid Improvement Plan period?
e. How did (or how will) DEC and DEP (collectively, "Duke") go about prioritizing and selecting substations for physical security upgrades?
f. How did Duke come to determine the $110 million budget for physical substation security upgrades? How does the value of this spending compare to the value to be delivered by other types of spending in the Grid Improvement Plan? How does Duke know it shouldn't spend less on substation security and more on other investments, or more on substation security and less on other investments?

Response:

a) 1759 in DEC NC
b) 12
c) 356 in DEP NC
d) 15
e) The Transmission Security Working Group determined the physical security requirements needed for substations that fell into the tiering for CIP-014 compliance, Tier 1 and Tier 2 classifications.
f) Duke Energy Transmission determined the $110M budget based on a threat and vulnerability assessment as well as the prioritization of the sites based on CIP-014, Tier 1 and Tier 2 classifications. Each project and program contained in the Grid Improvement Plan has unique and complementary value that address the megatrends described in witness Oliver testimony and Exhibits. The rate of investment mix contained within the Grid Improvement Plan was informed by Company experts and input from stakeholders.

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Feb 25 2020

NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-4

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.

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

Docket No. E-7, Sub 1214

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

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The attached response to NCSEA Data Request No. 2-52, 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

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Feb 25 2020

NCSEA
Data Request No. 2
DEC Docket No. E-7, Sub 1214
Item No. 2-52

Request:

52. Refer to Oliver Exhibit 10, page 50 (Enterprise Communications). Regarding "Mission Critical Voice" capital spending of $52.5 million:
a. Describe the existing Land Mobile Radio systems in place for DEC.
b. Describe any shortcomings associated with these systems.
c. Explain how the new system will avoid any shortcomings described.
d. Provide any analysis the Company completed comparing the cost of cellular service over the public cellular network to a new, proprietary voice network. If the Company has not completed such an analysis, please explain why not.

Response:

[Note: Clarification, the $52.5 million referenced in the question is for both DEC-NC and DEP-NC together; the correct value for just DEC-NC is $10.3 million]
a. The existing DEC Land Mobile Radio (LMR) system is a 2008 Harris Opensky 800MHz trunked-radio platform.
b. The existing Harris Opensky trunked-radio system will not be compatible with Duke Energy's enterprise wide communications strategy that is meant to migrate all jurisdictions onto a single LMR platform and improve operational excellence.
c. This platform provides enterprise wide interoperability, improves reliability, sustainability and portability.
d. A cost comparison of cellular services over the public cellular network was not performed. Cellular carriers could not meet the minimum requirements for mission critical communications.

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

Docket No. E-7, Sub 1214

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

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The attached response to NCSEA Data Request No. 2-53, 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

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Feb 25 2020

Request:

53. Refer to Oliver Exhibit 10, page 50 (Enterprise Communications). Regarding "Mission Critical (data) Transport" capital spending of $107.1 million:
a. Describe the existing (data) transport network.
b. Provide the annual operations and maintenance cost associated with the existing (data) transport network.
c. Describe any shortcomings associated with these systems.
d. Provide details regarding all the various upgrades anticipated, the locations and counts of each upgrade, and the cost of each upgrade such that the total equals $107.1 million.
e. Provide any analysis the Company completed comparing the cost of its proposed (data) Transport upgrades to other alternatives, including the use of new 4G LTE and Cat M-1 networks now available from public carriers. If the Company has not completed such an analysis, explain why not.

Response:

a. The Duke Energy (data) transport network is comprised of many components of various technologies. These include fiber, optical electronics, data management and routing platforms, as well as microwave and wireless technologies.

b.

RU	O&M
DEC	$21,700,431
DEP	$15,119,010

c. Aging physical infrastructure and technological advances have rendered many of the existing data transport platforms obsolete, with most no longer supported by vendors.

d. Data networks are systems comprised of multiple, various components; details regarding final locations and counts are subject to final engineering and design completion, which may occur once approved. The primary transport networks types, site counts and associated cost are included below. Specific location information about communications infrastructure of any kind is generally limited or not publicly available due to security concerns, from both physical and cyber perspectives.

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Feb 25 2020

DEC		
Site count	Technology	Cost
204	Microwave	$14,100,000
29	Fiber	$49,450,000
7	MAS Cambium	$ 750,000
	Region total	$64,300,000

DEP		
Site count	Technology	Cost
26	Microwave	$ 1,800,000
17	Fiber	$ 33,910,000
62	MAS Cambium	$ 7,100,000
	Region total	$ 42,810,000
	Program total	$107,110,000

Alternatives like 4G LTE and Cat M-1 do not have the capacity nor can they satisfy mission critical requirements to support an enterprise core data network. Given the inability to meet the requirements a cost analysis wasn't performed.

Alvarez (Corrected) Exhibit 10

CAPITAL DETAIL: BENEFIT-COST ANALYSES, NC ONLY

Program/Asset (Asset Life)	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	Source
Self-Optimizing Grid (30)																																
DEC (ADMS)	65,770,946	98,489,790	161,566,334	177,074,120	-	-	-	-	-	-	-	-	-	62,369,028	-	-	-	-	-	-	-	-	-	79,837,629	-	-	-	-	-	-	-	SOG_DEC_NC_19-22_vF_rev8 9-2-19.xlsx; tab "DEC North Carolina_SOG"; cells F17-I17
DEP	40,493,079	65,917,601	90,482,882	155,070,517	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	SOG_DEP_NC_19-22_vF_rev4 9-2-19.xlsx; tab "DEP North Carolina_SOG"; cells F17-I17
Integrated Volt-VAr Control (25)	307,933	40,407,172	118,498,991	117,499,135	93,937,955	-	-	-	2,172,641	6,426,808	6,323,677	8,969,071	11,262,013	11,723,951	9,205,802	2,480,782	29,681,046	63,149,599	65,804,226	50,242,793	-	5,299,110	17,483,816	23,749,355	20,357,427	6,889,842	-	-	-	-	-	IVVC_DEC_NC Only_19-23_vF_rev2 7-12-19.xlsx; tab "DEC-NC IVVC", cells G20-AF20
DSDR (25)	1,736,340	1,778,434	1,815,788	1,856,302	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	DSDR_DEP_NC Only_19-21_vF 5-6-19.xlsx; tab " "; cells
Transmission H&R (30)																																
DEC Line Projects (18.7% SC removed)	6,262,483	12,925,171	22,132,318	75,207,031	39,681,222	2,494,164	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Projects_DEC_NC-SC_19-21_multiple_vF_rev2 7-28-19. xlsx line 12 *81.3% (NC Portion)
DEP Line Projects (9.3% SC removed)	1,553,725	42,231	4,717,592	8,524,708	12,250,931	5,281,623	1,061,338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Projects_DEP_NC-SC_19-21_multiple_vF_rev2 7-28-19.xlsx line 12 *90.7% (NC Portion)
DEC Rebuilds (18.7% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_44kV Rebuilds_DEC_NC-SC_19_multiple_vF 1-26-19.xlsx line 12 * 81.3%
DEP Rebuilds (9.3% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Rebuilds_DEP_NC-SC_19_multiple_vF 2-19-19.xlsx line 12 * 90.7%
DEP Substation Flooding (9.3% SC removed)	3,085,614	6,778,918	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Flood Sub_Reinforce_DEP_NC-SC_19-20_All Program_vF 5-3-19.xlsx * .907 (NC Portion)
Transmission H&R: NC Only	10,901,822	19,746,320	26,849,910	83,731,739	51,932,153	7,775,787	1,061,338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Subs Flooding -- Whiteville Relo (30; 9.3% removed)				10,918,256																												Trans_Flood Sub_Rebuild_DEP_NC-SC_22_Whiteville_vF_rev1 7-17-19.xlsx & NCJC DR DEP x-xx
Targeted Undergrounding (35)	7,702,700	14,070,688	32,978,930	60,193,878	45,789,443	22,059,886	8,473,416	4,421,436	4,531,971																							TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx, tab "All Years Summary", line "Project Capital".
Energy Storage (307)		16,321,000	30,321,000	82,361,000																												
Distribution Trans Retrofit (35)	31,560,900	36,515,625	53,948,963	62,262,585																												HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx, tab "NPV - Tx Retrofit NC", cells E20-H20
Long Duration/High Impact Sites (35)	29,604,302	18,154,000	12,715,000	5,378,500	1,460,000																											LDI_DEC-DEP_NC_2019-2022_Summary_v1_rev1 7-9-19.xlsx, tab "2019-2022 Summary", cells D20-H20
Transformer Bank Replacement (30)																																
DEC total	5,712,000	6,537,040	8,798,354	5,851,393																												Trans_Transformer Bank_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEC SC (18.7%)	1,068,144	1,222,426	1,645,292	1,094,210																												NCJC DR DEC x-xx
DEC NC	4,643,856	5,314,614	7,153,062	4,757,182																												
DEP total	17,632,000	7,219,280	14,799,524	10,868,842																												Trans_Transformer Bank_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "
Less: DEP SC (9.3%)	1,639,776	671,393	1,376,356	1,010,802																												NCJC DR DEP x-xx
DEP NC	15,992,224	6,547,887	13,423,168	9,858,040																												
Oil Breaker Replacements (30)																																
DEC total	21,460,870	14,852,260	26,420,844	20,304,256																												Trans_Oil Breaker_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEC SC (18.7%)	4,013,183	2,777,373	4,940,698	3,796,896																												NCJC DR DEC x-xx
DEC NC	17,447,687	12,074,887	21,480,146	16,507,360																												
DEP total	9,051,260	8,783,891	6,055,939	19,182,760																												Trans_Oil Breaker_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEP SC (9.3%)	841,767	816,902	563,202	1,783,997																												NCJC DR DEP x-xx
DEP NC	8,209,493	7,966,989	5,492,737	17,398,764																												
Modernize																																
Enterprise Communications	-	52,797,000	68,160,000	90,861,000										271,144,948										347,088,457								Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Dist Auto (detail $194,069 does't tie to total)	-	52,464,000	50,744,000	90,861,000																												Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Transmission System Intelligence	-	30,837,000	41,601,000	13,973,000																												Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Enterprise Applications	-	5,709,000	6,351,000	15,787,000					31,506,325					35,646,514					40,330,759					45,630,552					51,626,781			Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Integrated Systems Operation Plan	-	4,858,000	612,000	1,180,000					7,523,865					8,512,562					9,631,183					10,896,799					12,328,728			Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
DER Dispatch Tool	-	2,856,000	3,339,000	1,252,000					8,425,597					9,532,790					10,785,476					12,202,777					13,806,322			Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Electric Transportation (30)	-	31,740,000	31,740,000	-																												Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Power Electronics for Volt/VAr Control	-	36,000	879,000	879,000																												Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
	-	181,297,000	203,426,000	214,793,000																												
Physical & Cyber Security	-	65,594,000	34,837,000	33,326,000																												Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
TOTALS	234,371,282	590,196,007	814,989,911	1,052,986,379	193,119,551	29,835,673	9,534,754	4,421,436	6,704,612	6,426,808	6,323,677	8,969,071	11,262,013	74,092,979	9,205,802	2,480,782	29,681,046	63,149,599	65,804,226	50,242,793	-	5,299,110	17,483,816	103,586,984	20,357,427	6,889,842	-	-	-	-	-	
CHECK																																
Remove Energy Storage	-	16,321,000	30,321,000	82,361,000																												
Remove Electric Transportation		31,740,000	31,740,000																													
COMPARE to OLIVER Exh. 10, p. 3 (cap budget)	234,371,282	542,135,007	752,928,911	970,625,379	193,119,551	29,835,673	9,534,754	4,421,436	6,704,612																							
Oliver Exh. 10	-	554,501,718	785,941,112	978,786,170	-	-	-	-	-																							
Difference	(234,371,282)	12,366,711	33,012,201	8,160,791	(193,119,551)	(29,835,673)	(9,534,754)	(4,421,436)	(6,704,612)																							
FOR REVENUE REQUIREMENT CALCULATIONS																																
total capital per BCAs	234,371,282	590,196,007	814,989,911	1,052,986,379	193,119,551	29,835,673	9,534,754	4,421,436	6,704,612	6,426,808	6,323,677	8,969,071	11,262,013	74,092,979	9,205,802	2,480,782	29,681,046	63,149,599	65,804,226	50,242,793	-	5,299,110	17,483,816	103,586,984	20,357,427	6,889,842	-	-	-	-	-	line 71
Programs with 10-year lives																																
ADMS portion of SOG	-	15,435,027	14,511,506	18,927,210	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	"Oliver Exh 10 Detail"
Enterprise Communications	-	52,796,973	68,159,906	90,860,239	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	"Oliver Exh 10 Detail"
Programs with 10-year lives total	-	68,232,000	82,671,412	109,787,449	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Programs with 5-year lives																																
Enterprise Applications	-	5,709,000	6,351,000	15,787,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	"Oliver Exh 10 Detail" for 2020-2022; "Short-lived Asset Table" 2023+
ISOP Programs	-	4,858,000	612,000	1,180,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	"Oliver Exh 10 Detail" for 2020-2022; "Short-lived Asset Table" 2023+
DER Dispatch Tool	-	2,856,000	3,339,000	1,252,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	"Oliver Exh 10 Detail" for 2020-2022; "Short-lived Asset Table" 2023+
Programs with 5-year lives total	-	13,423,000	10,302,000	18,219,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
All other programs' capital (30 yr life average)	234,371,282	508,541,007	722,016,499	924,979,930	193,119,551	29,835,673	9,534,754	4,421,436	6,704,612	6,426,808	6,323,677	8,969,071	11,262,013	74,092,979	9,205,802	2,480,782	29,681,046	63,149,599	65,804,226	50,242,793	-	5,299,110	17,483,816	103,586,984	20,357,427	6,889,842	-	-	-	-	-	

RR ESTIMATE: BENEFIT-COST ANALYSES, NC ONLY

ASSUMPTIONS

Return on Equity (%)	10.3%
Weighted Average Cost of Debt (%)	4.5%
Discount Rate (%)	6.8%
General Tax (% of Revenues)	4.0%
Income Tax (% of Return on Equity)	21.0%
Debt Ratio	47%

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	Source
REVENUE REQUIREMENT CALCULATION																																
Rate Base	226,558,906	782,483,370	1,528,806,980	2,467,671,849	2,540,232,572	2,448,514,894	2,338,863,072	2,226,010,950	2,156,826,947	2,039,695,127	1,922,249,387	1,813,973,271	1,715,881,838	2,041,737,578	1,915,193,440	1,781,841,589	1,674,700,633	1,598,923,245	1,582,943,316	1,488,979,777	1,344,773,444	1,205,689,585	1,078,207,638	1,518,094,420	1,378,416,850	1,225,042,034	1,064,777,376	904,512,717	820,203,550	658,132,551	503,873,928	
Debt	106,482,686	367,767,184	718,539,281	1,159,805,769	1,193,909,309	1,150,802,000	1,099,265,644	1,046,225,147	1,013,708,665	958,656,710	903,457,212	852,567,438	806,464,464	959,616,662	900,140,917	837,465,547	787,109,298	751,491,925	743,983,359	699,820,495	632,043,519	566,674,105	506,757,590	713,504,377	647,855,920	575,769,756	500,445,367	425,120,977	385,495,668	309,322,299	236,820,746	
Equity	120,076,220	414,716,186	810,267,699	1,307,866,080	1,346,323,263	1,297,712,894	1,239,597,428	1,179,785,804	1,143,118,282	1,081,038,417	1,018,792,175	961,405,834	909,417,374	1,082,120,917	1,015,052,523	944,376,042	887,591,336	847,429,320	838,959,957	789,159,282	712,729,925	639,015,480	571,450,048	804,590,042	730,560,931	649,272,278	564,332,009	479,391,740	434,707,881	348,810,252	267,053,182	
Return on Equity	12,367,851	42,715,767	83,457,573	134,710,206	138,671,296	133,666,428	127,678,535	121,517,938	117,741,183	111,346,957	104,935,594	99,024,801	93,669,990	111,458,454	104,550,410	97,270,732	91,421,908	87,285,220	86,412,876	81,283,406	73,411,182	65,818,594	58,859,355	82,872,774	75,247,776	66,875,045	58,126,197	49,377,349	44,774,912	35,927,456	27,506,478	
Income Tax	2,597,249	8,970,311	17,526,090	28,289,143	29,120,972	28,069,530	26,812,492	25,518,767	24,725,648	23,382,861	22,036,475	20,795,208	19,670,698	23,406,275	21,955,586	20,426,854	19,198,601	18,329,896	18,146,704	17,069,515	15,416,348	13,821,905	12,360,465	17,403,283	15,802,033	14,043,759	12,206,501	10,369,243	9,402,731	7,544,766	5,776,360	
Interest Expense	4,802,369	16,586,300	32,406,122	52,307,240	53,845,310	51,901,170	49,576,881	47,184,754	45,718,261	43,235,418	40,745,920	38,450,791	36,371,547	43,278,711	40,596,355	37,769,696	35,498,629	33,892,376	33,553,649	31,561,904	28,505,163	25,557,002	22,854,767	32,179,047	29,218,302	25,967,216	22,570,086	19,172,956	17,385,855	13,950,436	10,680,616	
O&M Expense	1,197,908	2,645,472	6,000,521	7,331,287	6,952,054	5,076,388	4,929,521	5,200,713	5,776,856	6,332,320	6,576,261	5,748,080	5,818,079	5,889,829	6,137,614	6,628,957	7,224,750	7,364,862	6,276,394	6,359,602	6,444,889	6,739,427	7,323,476	8,031,794	8,198,598	6,904,394	1,169,356	1,180,857	1,438,848	1,918,808	1,800,883	"BCA O&M Detail"
Total Depreciation	7,812,376	34,271,543	68,666,301	114,121,510	120,558,828	121,553,351	119,186,576	117,273,557	123,344,401	123,558,628	123,769,418	117,245,187	109,353,446	135,443,081	135,749,941	135,832,633	136,822,002	138,926,988	142,531,573	144,206,333	144,206,333	144,382,970	144,965,764	159,356,416	160,034,997	160,264,658	160,264,658	160,264,658	162,070,999	162,070,999	154,258,623	
Revenue Requirement, pre General Tax	28,777,753	105,189,394	208,056,606	336,759,387	349,148,461	340,264,867	328,184,005	316,695,729	317,306,350	307,856,184	298,063,668	281,264,067	264,883,760	319,476,350	308,989,906	297,928,873	290,165,889	285,799,342	286,921,196	280,480,760	267,983,915	256,319,898	246,363,826	299,843,314	288,501,706	274,055,072	254,336,799	240,365,064	235,073,345	221,412,464	200,022,959	
Plus: General Tax	1,151,110	4,207,576	8,322,264	13,470,375	13,965,938	13,610,595	13,127,360	12,667,829	12,692,254	12,314,247	11,922,547	11,250,563	10,595,350	12,779,054	12,359,596	11,917,155	11,606,636	11,431,974	11,476,848	11,219,230	10,719,357	10,252,796	9,854,553	11,993,733	11,540,068	10,962,203	10,173,472	9,614,603	9,402,934	8,856,499	8,000,918	
Total Revenue Requirement	29,928,863	109,396,969	216,378,871	350,229,762	363,114,399	353,875,462	341,311,366	329,363,559	329,998,604	320,170,431	309,986,215	292,514,630	275,479,110	332,255,404	321,349,502	309,846,028	301,772,525	297,231,316	298,398,044	291,699,990	278,703,271	266,572,694	256,218,379	311,837,046	300,041,774	285,017,275	264,510,271	249,979,667	244,476,278	230,268,963	208,023,878	
PRESENT VALUE OF REVENUE REQUIREMENT	3,485,299,451																														8,669,950,545	TOTAL Revenue requirement over 30 years
PRESENT VALUE OF RETURN ON EQUITY	1,165,706,056																														2,619,982,242	TOTAL return on equity over 30 years

DEPRECIATION TABLES (Balance of Wksht)

2019 Assets -- 30 year																															
Opening Balance	234,371,282	226,558,906	218,746,530	210,934,154	203,121,778	195,309,402	187,497,026	179,684,649	171,872,273	164,059,897	156,247,521	148,435,145	140,622,769	132,810,393	124,998,017	117,185,641	109,373,265	101,560,889	93,748,513	85,936,137	78,123,761	70,311,385	62,499,009	54,686,632	46,874,256	39,061,880	31,249,504	23,437,128	15,624,752	7,812,376	0	
Depreciation (30 years)	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	7,812,376	0	
Closing Balance	226,558,906	218,746,530	210,934,154	203,121,778	195,309,402	187,497,026	179,684,649	171,872,273	164,059,897	156,247,521	148,435,145	140,622,769	132,810,393	124,998,017	117,185,641	109,373,265	101,560,889	93,748,513	85,936,137	78,123,761	70,311,385	62,499,009	54,686,632	46,874,256	39,061,880	31,249,504	23,437,128	15,624,752	7,812,376	0	0	
2020 Assets -- 5 year																															
Opening Balance		13,423,000	10,738,400	8,053,800	5,369,200	2,684,600																									
Depreciation (5 years)		2,684,600	2,684,600	2,684,600	2,684,600	2,684,600																									
Closing Balance		10,738,400	8,053,800	5,369,200	2,684,600	-																									
2020 Assets -- 10 year																															
Opening Balance		68,232,000	61,408,800	54,585,600	47,762,400	40,939,200	34,116,000	27,292,800	20,469,600	13,646,400	6,823,200																				
Depreciation (10 years)		6,823,200	6,823,200	6,823,200	6,823,200	6,823,200	6,823,200	6,823,200	6,823,200	6,823,200	6,823,200																				
Closing Balance		61,408,800	54,585,600	47,762,400	40,939,200	34,116,000	27,292,800	20,469,600	13,646,400	6,823,200	-																				
2020 Assets -- 30 year																															
Opening Balance		508,541,007	491,589,640	474,638,273	457,686,906	440,735,539	423,784,172	406,832,806	389,881,439	372,930,072	355,978,705	339,027,338	322,075,971	305,124,604	288,173,237	271,221,870	254,270,503	237,319,137	220,367,770	203,416,403	186,465,036	169,513,669	152,562,302	135,610,935	118,659,568	101,708,201	84,756,834	67,805,468	50,854,101	33,902,734	16,951,367	
Depreciation (30 years)		16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	16,951,367	
Closing Balance		491,589,640	474,638,273	457,686,906	440,735,539	423,784,172	406,832,806	389,881,439	372,930,072	355,978,705	339,027,338	322,075,971	305,124,604	288,173,237	271,221,870	254,270,503	237,319,137	220,367,770	203,416,403	186,465,036	169,513,669	152,562,302	135,610,935	118,659,568	101,708,201	84,756,834	67,805,468	50,854,101	33,902,734	16,951,367	0	
2021 Assets -- 5 year																															
Opening Balance			10,302,000	8,241,600	6,181,200	4,120,800	2,060,400																								
Depreciation (5 years)			2,060,400	2,060,400	2,060,400	2,060,400	2,060,400																								
Closing Balance			8,241,600	6,181,200	4,120,800	2,060,400	-																								
2021 Assets -- 10 year																															
Opening Balance			82,671,412	74,404,271	66,137,130	57,869,988	49,602,847	41,335,706	33,068,565	24,801,424	16,534,282	8,267,141																				
Depreciation (10 years)			8,267,141	8,267,141	8,267,141	8,267,141	8,267,141	8,267,141	8,267,141	8,267,141	8,267,141	8,267,141																				
Closing Balance			74,404,271	66,137,130	57,869,988	49,602,847	41,335,706	33,068,565	24,801,424	16,534,282	8,267,141	(0)																				
2021 Assets -- 30 year																															
Opening Balance			722,016,499	697,949,283	673,882,066	649,814,849	625,747,633	601,680,416	577,613,199	553,545,983	529,478,766	505,411,549	481,344,333	457,277,116	433,209,899	409,142,683	385,075,466	361,008,250	336,941,033	312,873,816	288,806,600	264,739,383	240,672,166	216,604,950	192,537,733	168,470,516	144,403,300	120,336,083	96,268,867	72,201,650	48,134,433	
Depreciation (30 years)			24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	24,067,217	
Closing Balance			697,949,283	673,882,066	649,814,849	625,747,633	601,680,416	577,613,199	553,545,983	529,478,766	505,411,549	481,344,333	457,277,116	433,209,899	409,142,683	385,075,466	361,008,250	336,941,033	312,873,816	288,806,600	264,739,383	240,672,166	216,604,950	192,537,733	168,470,516	144,403,300	120,336,083	96,268,867	72,201,650	48,134,433	24,067,217	
2022 Assets -- 5 year																															
Opening Balance				18,219,000	14,575,200	10,931,400	7,287,600	3,643,800																								
Depreciation (5 years)				3,643,800	3,643,800	3,643,800	3,643,800	3,643,800																								
Closing Balance				14,575,200	10,931,400	7,287,600	3,643,800	-																								
2022 Assets -- 10 year																															
Opening Balance				109,787,449	98,808,704	87,829,959	76,851,214	65,872,469	54,893,725	43,914,980	32,936,235	21,957,490	10,978,745																				
Depreciation (10 years)				10,978,745	10,978,745	10,978,745	10,978,745	10,978,745	10,978,745	10,978,745	10,978,745	10,978,745	10,978,745																				
Closing Balance				98,808,704	87,829,959	76,851,214	65,872,469	54,893,725	43,914,980	32,936,235	21,957,490	10,978,745	-																				
2022 Assets -- 30 year																															
Opening Balance				924,979,930	894,147,266	863,314,601	832,481,937	801,649,273	770,816,608	739,983,944	709,151,280	678,318,615	647,485,951	616,653,287	585,820,622	554,987,958	524,155,294	493,322,629	462,489,965	431,657,301	400,824,636	369,991,972	339,159,308	308,326,643	277,493,979	246,661,315	215,828,650	184,995,986	154,163,322	123,330,657	92,497,993	
Depreciation (30 years)				30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	30,832,664	
Closing Balance				894,147,266	863,314,601	832,481,937	801,649,273	770,816,608	739,983,944	709,151,280	678,318,615	647,485,951	616,653,287	585,820,622	554,987,958	524,155,294	493,322,629	462,489,965	431,657,301	400,824,636	369,991,972	339,159,308	308,326,643	277,493,979	246,661,315	215,828,650	184,995,986	154,163,322	123,330,657	92,497,993	61,665,329	
2023 Assets -- 30 year																															
Opening Balance					193,119,551	186,682,232	180,244,914	173,807,596	167,370,277	160,932,959	154,495,641	148,058,322	141,621,004	135,183,685	128,746,367	122,309,049	115,871,730	109,434,412	102,997,094	96,559,775	90,122,457	83,685,139	77,247,820	70,810,502	64,373,184	57,935,865	51,498,547	45,061,228	38,623,910	32,186,592	25,749,273	
Depreciation (30 years)					6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	6,437,318	
Closing Balance					186,682,232	180,244,914	173,807,596	167,370,277	160,932,959	154,495,641	148,058,322	141,621,004	135,183,685	128,746,367	122,309,049	115,871,730	109,434,412	102,997,094	96,559,775	90,122,457	83,685,139	77,247,820	70,810,502	64,373,184	57,935,865	51,498,547	45,061,228	38,623,910	32,186,592	25,749,273	19,311,955	
2024 Assets -- 30 year																															
Opening Balance						29,835,673	28,841,151	27,846,628	26,852,106	25,857,583	24,863,061	23,868,539	22,874,016	21,879,494	20,884,971	19,890,449	18,895,926	17,901,404	16,906,882	15,912,359	14,917,837	13,923,314	12,928,792	11,934,269	10,939,747	9,945,224	8,950,702	7,956,180	6,961,657	5,967,135	4,972,612	
Depreciation (30 years)						994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	994,522	
Closing Balance						28,841,151	27,846,628	26,852,106	25,857,583	24,863,061	23,868,539	22,874,016	21,879,494	20,884,971	19,890,449	18,895,926	17,901,404	16,906,882	15,912,359	14,917,837	13,923,314	12,928,792	11,934,269	10,939,747	9,945,224	8,950,702	7,956,180	6,961,657	5,967,135	4,972,612	3,978,090	
2025 Assets -- 30 year																															
Opening Balance							9,534,754	9,216,929	8,899,104	8,581,278	8,263,453	7,945,628	7,627,803	7,309,978	6,992,153	6,674,328	6,356,503	6,038,677	5,720,852	5,403,027	5,085,202	4,767,377	4,449,552	4,131,727	3,813,902	3,496,076	3,178,251	2,860,426	2,542,601	2,224,776	1,906,951	
Depreciation (30 years)							317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	317,825	
Closing Balance							9,216,929	8,899,104	8,581,278	8,263,453	7,945,628	7,627,803	7,309,978	6,992,153	6,674,328	6,356,503	6,038,677	5,720,852	5,403,027	5,085,202	4,767,377	4,449,552	4,131,727	3,813,902	3,496,076	3,178,251	2,860,426	2,542,601	2,224,776	1,906,951	1,589,126	
2026 Assets -- 30 year																															
Opening Balance								4,421,436	4,274,054	4,126,673	3,979,292	3,831,911	3,684,530	3,537,148	3,389,767	3,242,386	3,095,005	2,947,624	2,800,243	2,652,861	2,505,480	2,358,099	2,210,718	2,063,337	1,915,955	1,768,574	1,621,193	1,473,812	1,326,431	1,179,049	1,031,668	
Depreciation (30 years)								147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	147,381	
Closing Balance								4,274,054	4,126,673	3,979,292	3,831,911	3,684,530	3,537,148	3,389,767	3,242,386	3,095,005	2,947,624	2,800,243	2,652,861	2,505,480	2,358,099	2,210,718	2,063,337	1,915,955	1,768,574	1,621,193	1,473,812	1,326,431	1,179,049	1,031,668	884,287	
2027 Assets -- 5 year																															
Opening Balance																															
Depreciation (5 years)																															
Closing Balance																															
2027 Assets -- 30 year																															
Opening Balance																															
Depreciation (30 years)																															
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Depreciation (5 years)																															
Closing Balance																															
2042 Assets -- 10 year																															
Opening Balance																															
Depreciation (10 years)																															
Closing Balance																															
2042 Assets -- 30 year																															

Opening Balance	103,586,984	100,134,084	96,681,185	93,228,285	89,775,386	86,322,486	82,869,587	79,416,687
Depreciation (30 years)	3,452,899	3,452,899	3,452,899	3,452,899	3,452,899	3,452,899	3,452,899	3,452,899
Closing Balance	100,134,084	96,681,185	93,228,285	89,775,386	86,322,486	82,869,587	79,416,687	75,963,788
2043 Assets – 30 year								
Opening Balance		20,357,427	19,678,846	19,000,266	18,321,685	17,643,104	16,964,523	16,285,942
Depreciation (30 years)		678,581	678,581	678,581	678,581	678,581	678,581	678,581
Closing Balance		19,678,846	19,000,266	18,321,685	17,643,104	16,964,523	16,285,942	15,607,361
2044 Assets – 30 year								
Opening Balance			6,889,842	6,660,181	6,430,519	6,200,858	5,971,196	5,741,535
Depreciation (30 years)			229,661	229,661	229,661	229,661	229,661	229,661
Closing Balance			6,660,181	6,430,519	6,200,858	5,971,196	5,741,535	5,511,874
2047 Assets – 5 year								
Opening Balance						77,761,831	62,209,465	46,657,099
Depreciation (5 years)						15,552,366	15,552,366	15,552,366
Closing Balance						62,209,465	46,657,099	31,104,733

RELIABILITY	Residential	Small C&I	Large C&I	Not Defined	Total Reliability	**ASSETS**	**Energy & Demand**	**O&M**	**Emissions (CO2)**	TOTAL PRIMARY	Oliver Exh. 8
TUG	30,213,660	374,938,080	1,476,355,783	4,959,802	1,886,467,325	47,287,983		107,410,608		2,041,165,916	2,041,165,916
Transformer Retrofit	7,172,999	149,957,793	82,802,426		239,933,218			10,071,665		250,004,883	250,004,884
IVVC					-		359,982,087	100,266,070	86,256,721	546,504,878	546,504,878
DSDR					-		192,539,000	16,619,000	57,192,000	266,350,000	232,348,694
SOG - DEC	46,986,086	623,932,977	379,618,459		1,050,537,522		78,997,663			1,129,535,185	1,129,535,184
SOG - DEP	46,312,439	739,265,853	139,399,592		924,977,884		34,251,650			959,229,534	959,229,534
DEP Oil Breaker Replacements	4,452,812	25,111,390	50,624,840		80,189,042	40,183,659				120,372,701	54,341,285
DEC Oil Breaker Replacements	4,132,045	27,771,507	12,178,530		44,082,082	15,833,130				59,915,212	97,863,006
DEP Trans Bank Replacements	1,790,862	4,141,082	1,340,491		7,272,435	29,355,623				36,628,058	33,221,648
DEC Trans Bank Replacements	2,493,132	7,434,531	4,521,460		14,449,123	14,102,246				28,551,369	23,212,261
Substation Flooding -- Reinforce					-	21,817,816	-	-		21,817,816	19,788,759
LDI/HIS	16,226,891	720,539,386	1,122,837,611		1,859,603,888	-	-	-		1,859,603,888	1,859,603,889
substation Relo -- Whiteville	1,110,580	375,873			1,486,453	4,964,803				6,451,255	5,851,288
Trans -- DEP line projects (less 9.7% SC)				88,673,349	88,673,349					88,673,349	89,066,144
Trans -- DEC line projects (less 18.3% SC)				1,908,658,683	1,908,658,683					1,908,658,683	1,899,313,965
Trans Upgrades -- DEP (less 9.7% SC)				-	-					-	
Trans Upgrades -- DEC (less 18.3% SC)				-	-					-	
TOTALS	160,891,506	2,673,468,472	3,269,679,192	2,002,291,835	8,106,331,004	173,545,259	665,770,400	234,367,343	143,448,721	9,323,462,727	9,241,051,335
	2.64%	43.80%	53.57%								

Reliability Benefits as a % of Total: 86.9%

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Program/Sub-Component	Present Value	2027	2032	2037	2042	2047
ADMS (Self-Optimizing Grid)	53,722,192	-	62,369,028	-	79,837,629	-
Enterprise Communications	233,553,437	-	271,144,948	-	347,088,457	-
Enterprise Applications	78,380,613	31,506,325	35,646,514	40,330,759	45,630,552	51,626,781
ISOP Programs	18,717,674	7,523,865	8,512,562	9,631,183	10,896,799	12,328,728
DER Dispatch Tool	20,960,980	8,425,597	9,532,790	10,785,476	12,202,777	13,806,322
Total	405,334,895	47,455,786	387,205,842	60,747,418	495,656,214	77,761,831

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Oliver Exh. 10 Capital Detail NC ONLY	DEC			DEP			TOTAL			
	2020	2021	2022	2020	2021	2022	2020	2021	2022	GIP TOTAL
TOTALS	326,766,615	454,473,324	550,147,959	227,735,103	331,467,788	428,638,211	554,501,718	785,941,112	978,786,170	2,319,229,000
Self-Optimizing Grid (Total)	90,604,000	153,733,000	175,802,000	61,528,000	86,057,000	154,752,000	152,132,000	239,790,000	330,554,000	722,476,000
Fixed Costs (ADMS and POC)	9,417,344	8,853,752	11,516,811	6,017,683	5,657,754	7,410,399	15,435,027	14,511,506	18,927,210	48,873,743
Variable Costs (segments/capacity/conn)	81,186,656	144,879,248	164,285,189	55,510,317	80,399,246	147,341,601	136,696,973	225,278,494	311,626,790	673,602,257
Integrated Volt-VAr Control (total)	30,797,000	86,311,000	89,550,000	-	5,000,000	5,000,000	30,797,000	91,311,000	94,550,000	216,658,000
Transmission H & R (Total)	13,985,730	20,417,670	68,058,900	8,933,625	9,568,905	12,785,010	22,919,355	29,986,575	80,843,910	133,749,840
Line H&R (Trans + Distribution)	11,966,400	20,417,670	68,058,900	595,575	8,735,100	10,799,760	12,561,975	29,152,770	78,858,660	120,573,405
Substation Flooding	-	-	-	8,338,050	794,100	1,588,200	8,338,050	794,100	1,588,200	10,720,350
Substation Animal Mitigation	2,019,330	-	-	-	39,705	397,050	2,019,330	39,705	397,050	2,456,085
Targeted Undergrounding	6,424,000	15,313,000	38,104,000	8,628,000	19,524,000	26,550,000	15,052,000	34,837,000	64,654,000	114,543,000
Distribution Transformer Retrofit	-	-	8,293,000	30,105,000	42,053,000	37,568,000	30,105,000	42,053,000	45,861,000	118,019,000
Long Dur Interruption/High Impact Sites	2,354,000	5,725,000	3,245,000	6,881,000	4,978,000	3,912,000	9,235,000	10,703,000	7,157,000	27,095,000
Transmission Transformer Bank Replace	6,193,000	18,174,000	9,274,000	25,019,000	38,514,000	19,217,000	31,212,000	56,688,000	28,491,000	116,391,000
Oil Breaker Replacements	28,244,000	53,998,000	33,415,000	19,654,000	20,051,000	44,925,000	47,898,000	74,049,000	78,340,000	200,287,000
Enterprise Communications Total	26,989,547	35,877,788	40,895,277	25,807,426	32,282,118	49,964,962	52,796,973	68,159,906	90,860,239	211,817,118
Next Gen Cellular	1,765,025	2,918,856	1,430,751	2,617,183	2,617,183	255,978	4,382,208	5,536,039	1,686,729	11,604,976
Mission Critical Voice	227,406	-	10,084,885	146,103	12,948,245	29,061,474	373,509	12,948,245	39,146,359	52,468,113
POC	394,315	0	0	256,149	0	0	650,464	-	-	650,464
Biz WAN	0	149,505	149,505	0	158,741	158,741	-	308,246	308,246	616,492
Grid WAN	4,214,704	1,208,846	747,900	5,198,889	2,617,544	79,410	9,413,593	3,826,390	827,310	14,067,293
Mission Critical Data Transport	16,784,625	24,107,526	23,408,744	13,322,647	11,355,628	18,129,300	30,107,272	35,463,154	41,538,044	107,108,470
Towers Shelters Pow Sup	2,450,868	6,961,068	4,815,343	3,515,481	2,317,612	2,110,765	5,966,349	9,278,680	6,926,108	22,171,137
Network Asset Systems	312,240	407,387	258,149	202,832	267,165	169,294	515,072	674,552	427,443	1,617,067
Vehical Area Network	840,364	124,600	-	548,142	-	-	1,388,506	124,600	-	1,513,106
Distribution Automation	36,142,000	17,863,000	61,382,000	16,322,000	32,881,000	29,696,000	52,464,000	50,744,000	91,078,000	194,286,000
Transmission System Intelligence	24,008,000	30,290,000	8,414,000	6,829,000	11,311,000	5,559,000	30,837,000	41,601,000	13,973,000	86,411,000
Enterprise Applications	4,348,000	3,140,000	9,555,000	1,361,000	3,211,000	6,232,000	5,709,000	6,351,000	15,787,000	27,847,000
Integrated Systems Operations Planning	3,028,000	379,000	749,000	1,830,000	233,000	431,000	4,858,000	612,000	1,180,000	6,650,000
DER Dispatch Tool	1,738,000	2,032,000	762,000	1,118,000	1,307,000	490,000	2,856,000	3,339,000	1,252,000	7,447,000
Power Electronics for Volt/VAr Control	-	347,000	347,000	36,000	532,000	532,000	36,000	879,000	879,000	1,794,000
Physical and Cyber Security Total	51,911,338	10,872,866	2,301,782	13,683,052	23,964,765	31,024,239	65,594,390	34,837,631	33,326,021	133,758,042
Substation Phys Security	47,117,700	7,254,630	-	7,742,475	20,170,140	28,428,780	54,860,175	27,424,770	28,428,780	110,713,725
Windows Based Unit Change outs	822,690	-	-	-	-	-	822,690	-	-	822,690
Device Entry Alert System	1,197,327	745,237	0	770,410	479,416	0	1,967,737	1,224,653	-	3,192,390
Secure Access Device Mgmt	1,728,621	1,512,999	1,021,782	1,112,267	973,527	657,464	2,840,888	2,486,526	1,679,246	7,006,660
Line Device Protection**	1,045,000	1,360,000	1,280,000	4,057,900	2,341,682	1,937,995	5,102,900	3,701,682	3,217,995	12,022,577
Mission Critical Voice & Data Total	17,012,031	24,107,526	33,493,629	13,468,750	24,303,873	47,190,774	30,480,781	48,411,399	80,684,403	159,576,583
Enterprise Comm's Total w/o	309,754,584	430,365,798	516,654,330	214,266,353	307,163,915	381,447,437	524,020,937	737,529,713	898,101,767	2,159,652,417

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

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	DEC			DEP			TOTAL			
	2020	2021	2022	2020	2021	2022	2020	2021	2022	GIP TOTAL
TOTALS	51,911,338	10,872,866	2,301,782	13,683,052	23,964,765	31,024,239	65,594,390	34,837,631	33,326,021	133,758,042
Substation Phys Security	47,117,700	7,254,630	-	7,742,475	20,170,140	28,428,780	54,860,175	27,424,770	28,428,780	110,713,725
Windows Based Unit Change outs	822,690	-	-	-	-	-	822,690	-	-	822,690
Device Entry Alert System	1,197,327	745,237	0	770,410	479,416	0	1,967,737	1,224,653	-	3,192,390
Secure Access Device Mgmt	1,728,621	1,512,999	1,021,782	1,112,267	973,527	657,464	2,840,888	2,486,526	1,679,246	7,006,660
Line Device Protection**	1,045,000	1,360,000	1,280,000	4,057,900	2,341,682	1,937,995	5,102,900	3,701,682	3,217,995	12,022,577

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	DEC			DEP			TOTAL			
	2020	2021	2022	2020	2021	2022	2020	2021	2022	GIP TOTAL
TOTALS	26,989,547	35,877,788	40,895,277	25,807,426	32,282,118	49,964,962	52,796,973	68,159,906	90,860,239	211,817,118
Next Gen Cellular	1,765,025	2,918,856	1,430,751	2,617,183	2,617,183	255,978	4,382,208	5,536,039	1,686,729	11,604,976
Mission Critical Voice	227,406	-	10,084,885	146,103	12,948,245	29,061,474	373,509	12,948,245	39,146,359	52,468,113
POC	394,315	0	0	256,149	0	0	650,464	-	-	650,464
Biz WAN	0	149,505	149,505	0	158,741	158,741	-	308,246	308,246	616,492
Grid WAN	4,214,704	1,208,846	747,900	5,198,889	2,617,544	79,410	9,413,593	3,826,390	827,310	14,067,293
Mission Critical Data Transport	16,784,625	24,107,526	23,408,744	13,322,647	11,355,628	18,129,300	30,107,272	35,463,154	41,538,044	107,108,470
Towers Shelters Pow Sup	2,450,868	6,961,068	4,815,343	3,515,481	2,317,612	2,110,765	5,966,349	9,278,680	6,926,108	22,171,137
Network Asset Systems	312,240	407,387	258,149	202,832	267,165	169,294	515,072	674,552	427,443	1,617,067
Vehical Area Network	840,364	124,600	-	548,142	-	-	1,388,506	124,600	-	1,513,106
Mission Critical Voice & Data Total	17,012,031	24,107,526	33,493,629	13,468,750	24,303,873	47,190,774	30,480,781	48,411,399	80,684,403	159,576,583
Enterprise Comm's Total w/o	9,977,516	11,770,262	7,401,648	12,338,676	7,978,245	2,774,188	22,316,192	19,748,507	10,175,836	52,240,535

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O&M DETAIL: BENEFIT-COST ANALYSES, NC ONLY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	Source
Self-Optimizing Grid																																
DEC	-	23,289	65,005	190,110	2,221,548	409,125	409,469	514,657	628,598	1,006,095	1,012,559	411,319	411,718	412,126	537,161	672,605	1,121,291	1,128,851	414,326	414,799	415,284	563,911	724,911	1,258,312	1,267,455	417,899	418,462	419,039	595,711	702,941	732,729	SOG_DEC_NC_19-22_vF_rev8 9-2-19.xlsx; tab "DEC North Carolina_SOG"; line 25 (Total O&M)
DEP	-	9,274	85,879	108,828	136,147	323,341	323,577	365,567	602,160	661,573	707,160	324,845	325,118	325,398	375,311	656,551	727,133	781,247	326,906	327,230	327,563	386,893	721,197	805,149	869,573	329,355	329,741	330,136	400,662	762,201	603,144	SOG_DEP_NC_19-22_vF_rev4 9-2-19.xlsx; tab "DEP North Carolina_SOG"; line 25 (Total O&M)
Integrated Volt-VAr Control	-	1,073,108	3,209,001	3,321,881	3,143,520	3,524,838	3,737,059	3,952,553	4,168,963	4,387,872	4,572,842	4,721,124	4,783,182	4,846,791	4,911,991	4,978,821	5,047,322	5,117,535	5,189,503	5,263,271	5,338,882	5,416,384	5,495,824	5,577,250	5,660,711	5,746,259	-	-	-	-	-	IVVC_DEC_NC Only_19-23_vF_rev2 7-12-19.xlsx; tab "DEC-NC IVVC", line 29 (Total O&M)
DSDR	20,000	20,000	21,000	21,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	DSDR_DEP_NC Only_19-21_vF 5-6-19.xlsx; tab "DSDR", line 28
Transmisison H&R																																
DEC Line Projects (18.7% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Projects_DEC_NC-SC_19-21_multiple_vF_rev2 7-28-19. xlsx & NCJC DR DEC x-xx
DEP Line Projects (9.3% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Projects_DEP_NC-SC_19-21_multiple_vF_rev2 7-28-19.xlsx S NCJC DR DEP x-xx
DEC Rebuilds (18.7% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_44kV Rebuilds_DEC_NC-SC_19_multiple_vF 1-26-19.xlsx & NCJC DR DEC x-xx
DEP Rebuilds (9.3% SC removed)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Line Rebuilds_DEP_NC-SC_19_multiple_vF 2-19-19.xlsx & NCJC DR DEP x-xx
Substation Flooding (SC?)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Flood Sub_Reinforce_DEP_NC-SC_19-20_All Program_vF 5-3-19 & NCHC DR DEP x-xx
Transmission H&R: NC Only	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Substation Flooding -- Whiteville Relo	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Trans_Flood Sub_Rebuild_DEP_NC-SC_22_Whiteville_vF_rev1 7-17-19.xlsx & NCJC DR DEP x-xx
Targeted Undergrounding	231,081	424,333	1,001,167	1,821,590	1,450,840	819,083	459,417	367,936	377,135	276,780	283,699	290,792	298,062	305,513	313,151	320,980	329,004	337,229	345,660	354,302	363,159	372,238	381,544	391,083	400,860	410,881	421,153	431,682	442,474	453,536	464,874	TUG_DEC-DEP_NC_19-22_Consolidated_vF rev1 8-9-19.xlsx, tab "All Years Summary", line 20 (O&M).
Energy Storage		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Distribution Trans Retrofit	946,827	1,095,469	1,618,469	1,867,878	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	HR_Transformer Retro_DEC-DEP_NC_19-22_vF_rev2 8-2-19.xlsx, tab "NPV - Tx Retrofit NC", line 22 (Program O&M co
Long Duration/High Impact Sites	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	LDI_DEC-DEP_NC_2019-2022_Summary_v1_rev1 7-9-19.xlsx, tab "2019-2022 Summary"
Transformer Bank Replacement																																
DEC total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	Trans_Transformer Bank_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEC SC (18.3%)																																NCJC DR DEC x-xx
DEC NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	
DEP total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	Trans_Transformer Bank_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "
Less: DEP SC (9.3%)																																NCJC DR DEP x-xx
DEP NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	
Oil Breaker Replacements																																
DEC total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	Trans_Oil Breaker_DEC_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEC SC (18.3%)																																NCJC DR DEC x-xx
DEC NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	
DEP total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	Trans_Oil Breaker_DEP_NC-SC_19-22_vF_rev3 8-2-19.xlsx, tab "NPV", cells D18-G18
Less: DEP SC (9.3%)																																NCJC DR DEP x-xx
DEP NC	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	
Modernize																																
Enterprise Communications	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Dist Auto	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Transmission System Intelligence	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Enterprise Applications	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Integrated Systems Operation Plan	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
DER Dispatch Tool	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Electric Transportation	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
Power Electronics for Volt/VAr Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	
Physical & Cyber Security	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	26	27	Oliver Exh. 10, page 3 (GIP Capital Budget Summary, NC Budget)
TOTALS	1,197,908	2,645,472	6,000,521	7,331,287	6,952,054	5,076,388	4,929,521	5,200,713	5,776,856	6,332,320	6,576,261	5,748,080	5,818,079	5,889,829	6,137,614	6,628,957	7,224,750	7,364,862	6,276,394	6,359,602	6,444,889	6,739,427	7,323,476	8,031,794	8,198,598	6,904,394	1,169,356	1,180,857	1,438,848	1,918,808	1,800,883	

Alvarez Exhibit-11

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Feb 25 2020

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

Docket No. E-7, Sub 1214

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

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[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 8-27, 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

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Feb 25 2020

NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-27

Request:

8-27. Refer to DEC's response to NCJC DR 5-53, which states "In the last 5 years, Conductor failures on the DEC 44kV Transmission system have resulted in 14,008 customer outages, totaling 2,180,102 customer minutes interrupted."
a. How many individual conductor failures are represented in these statistics?
b. How many miles of 44kV lines does DEC have?

Response:

a. Individual conductor assets are not tracked to specific outages in the Transmission Reliability Reporting System, although there were 8 unique events that comprised the above-mentioned customer interruptions and customer minutes interrupted.
b. Approximately 2,800 miles

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Feb 25 2020

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

Docket No. E-2, Sub 1219

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

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The attached response to NCJC Data Request No. 5-18, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Feb 25 2020

NCJC
Data Request No. 5
DEP Docket No. E-2, Sub 1219
Item No. 5-18

Request:

5-18. Refer to DEP's response to NCJC DEP DR 2-17(f), which states "In the last 5 years, Conductor failures on the DEC 44kV Transmission system have resulted in 14,008 customer outages, totaling 2,180,102 customer minutes interrupted."
a. How many individual instances of 44kV conductor failure are represented in these statistics?
b. How many miles of 44kV lines does DEP have?

Response:

a. This question is not applicable to DEP since DEP has no 44kV transmission lines.
b. 0 miles

Alvarez Exhibit-12

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Feb 25 2020

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

Docket No. E-7, Sub 1214

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

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The attached response to NCJC Data Request No. 8-28, 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

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NCJC
Data Request No. 8
DEC Docket No. E-7, Sub1214
Item No. 8-28

Request:

8-28. Refer to DEC's response to NCJC DR 5-54, which states ". . . in the last 5 years, line equipment failures on the DEC 44kV Transmission system have resulted in 111,477 customer outages, totaling 21,179,109 customer minutes interrupted."
a. How many individual instances of line equipment failures are represented in these statistics?
b. How many individual pieces of 44kV line equipment does DEC have today?

Response:

a. 85 unique events are represented in the referenced statistics.
b. Line equipment assets are not all uniquely tracked and identified as pieces of equipment in the Duke Energy Transmission Asset Management system, therefore a number cannot be provided. Example of line equipment include: Conductor, Static, Crossarms, Poles, Guy Wire, Insulators, Connectors, Clamps, Jumpers, Cross Braces, Switches, Hardware. A 44kV line rebuild project replaces all of these assets on a given line.

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

Docket No. E-2, Sub 1219

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

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The attached response to NCJC Data Request No. 5-19, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Feb 25 2020

NCJC
Data Request No. 5
DEP Docket No. E-2, Sub 1219
Item No. 5-19

Request:

5-19. Refer to DEP's response to NCJC DEP DR 2-18(d), which states "In the last 5 years, DEP Line Equipment failures have resulted in 155,091 customer outages, totaling 10,707,502 customer minutes interrupted."
a. How many individual instances of 44kV conductor failure are represented in these statistics?
b. How many miles of 44kV lines does DEP have?

Response:

a. This question is not applicable to DEP since DEP has no 44kV transmission lines.
b. 0 miles
With regards to NCJC DEP DR 2-18(d), which states "In the last 5 years, DEP Line Equipment failures have resulted in 155,091 customer outages, totaling 10,707,502 customer minutes interrupted" the following is applicable:
• 14 unique events are represented in the referenced statistics.
• Line equipment assets are not all uniquely tracked and identified as pieces of equipment in the Duke Energy Transmission Asset Management system, therefore a number cannot be provided. Examples of line equipment include: Conductor, Static, Crossarms, Poles, Guy Wire, Insulators, Connectors, Clamps, Jumpers, Cross Braces, Switches, Hardware.

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Feb 25 2020

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

Docket No. E-7, Sub 1214

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

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The attached response to NCSEA Data Request No. 3-11, 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

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Feb 25 2020

NCSEA
Data Request No. 3
DEC Docket No. E-7, Sub 1214
Item No. 3-11

Request:

Refer to Duke's response to NCSEA DR2-38, which defines multiplier for cleared operations as "This is the relationship between sustained operations and momentary operations such that for every 1 sustained interruption we would expect to have 2.7 momentary interruptions. It is used to estimate the Annual Momentary Events in the calculation of the customer Momentary Interruption Cost Avoided values."
a. Provide all data sources, work sheets and calculations, including all relay settings, coordination curves, work processes, policies, and other information used to justify 2.7 momentaries per sustained outage.
b. Use an example to explain how 2.7 momentaries would typically result from one sustained outage.

Response:

a. See attached file "1997-2010 DEC SAIFI and MAIFI.xlsx"
b. The attached file shows the very strong correlation between SAIFI & MAIFI with a R2 of 86%. If SAIFI is set equal to 1 in the trendline formula the MAIFI equals approximately 2.7 which means that for every 1 sustained interruption the average customer experiences they will experience 2.7 momentary interruptions.

NCSEA 3-11
1997-2010 DEC SAIFI

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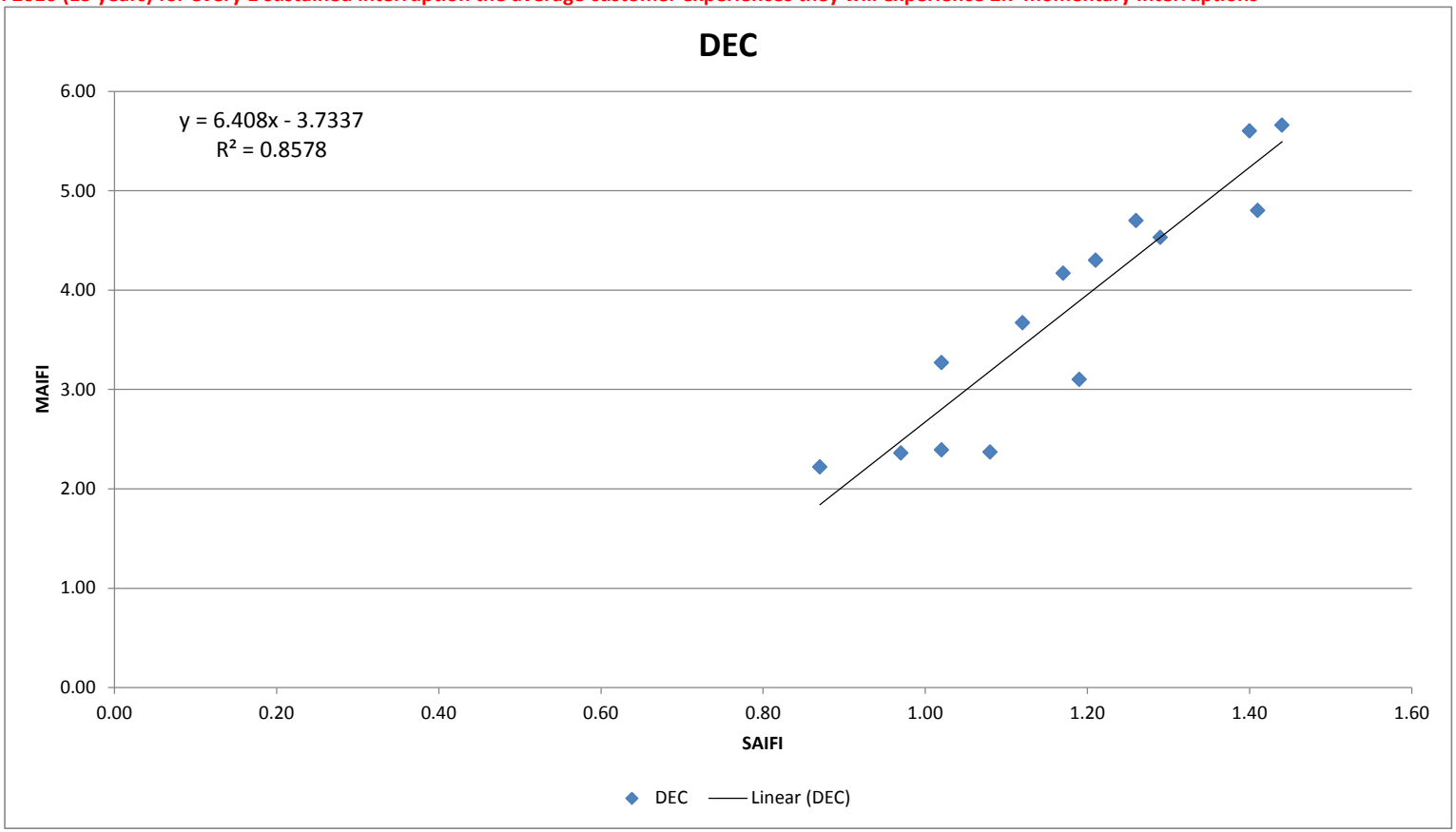
Based on DEC data from 1997 through 2010 (13 years) for every 1 sustained interruption the average customer experiences they will experience 2.7 momentary interruptions

DEC	SAIFI	$MAIFI_{(Breaker)}$
1997	1.40	5.60
1998	1.44	5.66
1999	1.41	4.80
2000	1.29	4.53
2001	1.17	4.17
2002	1.21	4.30
2003	1.26	4.70
2004	1.02	3.27
2005	1.12	3.67
2006	1.19	3.10
2007	0.97	2.36
2008	1.08	2.37
2009	0.87	2.22
2010	1.02	2.39



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Feb 25 2020

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

Docket No. E-7, Sub 1214

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

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 5-32, 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

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Feb 25 2020

NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-32

Request:

5-32. Refer to DEC's response to NCSEA DR 3-26 (b), which states: "Duke does not currently track, record, or report momentary outages. For estimation of momentary interruptions refer to the responses for NCSEA 3-11." Refer also to NCSEA DR 3-11, which indicates that momentaries per sustained outage are calculated using a MAIFI (momentary) per SAIFI ratio.
a. Explain how DEC derived the MAIFI values employed in the response to NCSEA DR 3-11 if it is does not track momentary outages.
b. Provide MAIFI(Breaker) and SAIFI data for each year from 2011 to 2018 for DEC. If this data is not available, explain why DEC stopped tracking MAIFI data after 2010.

Response:

a. As indicated in the Excel spreadsheet supporting the company's response to NCSEA DR 3-11 (titled NCSEA 3-11 1997-2010 DEC SAIFI and MAIFI) the MAIFI is the substation breakers in DEC where momentary operations were recorded & stored from 1997 – 2010.
b. MAIFIBreaker is not available after 2010. The company stopped the manual process of capturing & storing MAIFIBreaker after 2010 because the program used to store the data became obsolete.

Alvarez Exhibit-14

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

Docket No. E-7, Sub 1214

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

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The attached response to NCJC Data Request No. 5-10, 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

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Feb 25 2020

NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-10

Request:

5-10. Refer to the Oliver testimony regarding the Grid Improvement Plan generally. Assume that all aspects of Duke's Grid Improvement Plan are approved. Provide the improvement over 2018 DEC SAIDI, with and without major event days, Duke expects the Plan will deliver, as well as the year by which Duke expects the improvements to be reflected.

Response:

See attached Excel spreadsheet titled "PS DR 36-5 DEC GIP SAIFI-SAIDI Savings By Year 2019 - 2025 (Revised 11-19-19)". The Company has not done any GIP SAIDI reduction analysis associated with MEDs because their frequency and impact are highly variable from year-to-year.

PS DR 36-5 DEC GIP SAIFI-SAIDI Savings B

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Feb 25 2020

Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
Public Staff Data Request No. 36-5 (Revised 11-19-19)

DEC 2019 - 2024 Scope	Estimated Incremental SAIDI Minutes Reduction in 2019	Estimated Incremental SAIDI Minutes Reduction in 2020	Estimated Incremental SAIDI Minutes Reduction in 2021	Estimated Incremental SAIDI Minutes Reduction in 2022	Estimated Incremental SAIDI Minutes Reduction in 2023	Estimated Incremental SAIDI Minutes Reduction in 2024	Estimated Incremental SAIDI Minutes Reduction in 2025
Total	**2.07**	**1.75**	**4.78**	**8.75**	**10.52**		
SOG	2.07	0.99	3.38	6.65	6.81		
TUG	0.00	0.05	0.22	0.33	0.55		
Transformer Retrofit	0.00	0.09	0.00	0.00	0.00	N/A*	N/A*
LDO/ HIS	0.00	0.55	0.75	1.01	1.15		
Hydraulic Recloser Replacement	0.00	0.07	0.21	0.00	0.10		
Fuse Replacement	0.00	0.00	0.23	0.75	1.90		
Projected # of Customers Served	2,598,518	2,631,647	2,665,198	2,699,177	2,733,589		

DEC 2019 - 2024 Scope	Estimated Incremental SAIFI Reduction in 2019	Estimated Incremental SAIFI Reduction in 2020	Estimated Incremental SAIFI Reduction in 2021	Estimated Incremental SAIFI Reduction in 2022	Estimated Incremental SAIFI Reduction in 2023	Estimated Incremental SAIFI Reduction in 2024	Estimated Incremental SAIFI Reduction in 2025
Total	**0.0166**	**0.0091**	**0.0224**	**0.0460**	**0.0660**		
SOG	0.0166	0.0077	0.0178	0.0379	0.0472		
TUG	0.0000	0.0002	0.0010	0.0015	0.0024		
Transformer Retrofit	0.0000	0.0005	0.0000	0.0000	0.0000	N/A*	N/A*
LDO/ HIS	0.0000	0.0003	0.0006	0.0009	0.0012		
Hydraulic Recloser Replacement	0.0000	0.0004	0.0013	0.0000	0.0006		
Fuse Replacement	0.0000	0.0000	0.0017	0.0057	0.0145		
Projected # of Customers Served	2,598,518	2,631,647	2,665,198	2,699,177	2,733,589		

* The current GIP scope ends in 2022 so there are no estimated **incremental** SAIDI/SAIFI savings beyond 2023

NOTE: We have not included the effect of transmission programs in these estimates, although transmission Grid Improvement programs will certainly improve system reliability. These programs are not quantified because transmission failures occur on a much more infrequent basis and therefore we cannot accurately predict short term impacts on SAIDI and SAIFI. However, when transmission outages do occur they typically affect a large number of customers.

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Feb 25 2020

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

Docket No. E-2, Sub 1219

Date of Request: **January 16, 2020**
Date of Response: **January 24, 2020**

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☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCJC Data Request No. 2-7, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to NCJC under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Progress

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Feb 25 2020

NCJC
Data Request No. 2
DEP Docket No. E-2, Sub 1219
Item No. 2-7
Page 1 of 1

Request:

2-7. Refer to the Oliver testimony regarding the Grid Improvement Plan generally. Assume that all aspects of Duke's Grid Improvement Plan are approved. Provide the improvement over 2018 DEP SAIDI, with and without major event days, Duke expects the Plan will deliver, as well as the year by which Duke expects the improvements to be reflected.

Response:

See attached Excel spreadsheet titled "PS DR 21-11 for the DEP GIP SAIFI-SAIDI Savings By Year 2019 – 2025". The Company has not done any GIP SAIDI reduction analysis associated with MEDs because their frequency and impact are highly variable from year-to-year.

PS DR 21-11 DEP
GIP SAIFI-SAIDI Savir

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DEP 2019 - 2023 Scope	Estimated Incremental SAIDI Minutes Reduction in 2019	Estimated Incremental SAIDI Minutes Reduction in 2020	Estimated Incremental SAIDI Minutes Reduction in 2021	Estimated Incremental SAIDI Minutes Reduction in 2022	Estimated Incremental SAIDI Minutes Reduction in 2023	Estimated Incremental SAIDI Minutes Reduction in 2024	Estimated Incremental SAIDI Minutes Reduction in 2025
Total	**13.00**	**2.88**	**10.69**	**12.02**	**12.99**	N/A*	N/A*
SOG	13.00	2.28	7.91	7.25	8.00		
TUG	0.00	0.00	0.04	0.15	0.27		
Transformer Retrofit	0.00	0.37	0.52	0.73	0.72		
LDO/ HIS	0.00	0.08	1.68	2.22	2.56		
Hydraulic Recloser Replacement	0.00	0.12	0.20	0.11	0.06		
Fuse Replacement	0.00	0.03	0.34	1.57	1.39		
Projected # of Customers Served	1,572,852	1,594,854	1,617,163	1,639,785	1,662,723		

DEP 2019 - 2023 Scope	Estimated Incremental SAIFI Reduction in 2019	Estimated Incremental SAIFI Reduction in 2020	Estimated Incremental SAIFI Reduction in 2021	Estimated Incremental SAIFI Reduction in 2022	Estimated Incremental SAIFI Reduction in 2023	Estimated Incremental SAIFI Reduction in 2024	Estimated Incremental SAIFI Reduction in 2025
Total	**0.0823**	**0.0190**	**0.0694**	**0.1032**	**0.0880**	N/A*	N/A*
SOG	0.0823	0.0141	0.0457	0.0652	0.0495		
TUG	0.0000	0.0000	0.0005	0.0014	0.0022		
Transformer Retrofit	0.0000	0.0037	0.0052	0.0073	0.0072		
LDO/ HIS	0.0000	0.0002	0.0141	0.0167	0.0181		
Hydraulic Recloser Replacement	0.0000	0.0008	0.0013	0.0007	0.0004		
Fuse Replacement	0.0000	0.0002	0.0026	0.0119	0.0106		
Projected # of Customers Served	1,572,852	1,594,854	1,617,163	1,639,785	1,662,723		

* The current GIP scope ends in 2022 so there are no estimated **incremental** SAIDI/SAIFI savings beyond 2023

NOTE: We have not included the effect of transmission programs in these estimates, although transmission Grid Improvement programs will certainly improve system reliability. These programs are not quantified because transmission failures occur on a much more infrequent basis and therefore we cannot accurately predict short term impacts on SAIDI and SAIFI. However, when transmission outages do occur they typically affect a large number of customers.

Alvarez Exhibit-15

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Feb 25 2020

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**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NCSEA Data Request No. 2-16, 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

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Feb 25 2020

NCSEA
Data Request No. 2
DEC Docket No. E-7, Sub 1214
Item No. 2-16
Page 1 of 1

Request:

16. Refer to the Oliver testimony regarding stakeholder engagement generally, pages 45-50.
a. Indicate where in any stakeholder engagement presentation or materials Duke Energy presented the likely rate impact of its $2.5 billion Grid Improvement Plan.
b. Indicate where in any stakeholder engagement presentation or materials Duke Energy presented the impact on the average residential customer's bill of its $2.5 billion Grid Improvement Plan.
c. Describe any input Duke Energy received from Stakeholders regarding the overall size of the Grid Improvement Plan, which Duke Energy estimated at $1.6-$2.5 billion over 3 years in stakeholder engagement presentations and materials.
d. Describe any changes Duke Energy made to the overall size of the Grid Improvement Plan, which Duke Energy estimated at $1.6-$2.5 billion over 3 years in stakeholder engagement presentations and materials, as a result of stakeholder feedback.

Response:

a. None.
b. None.
c. Please see Witness Oliver's direct testimony, Exhibits 11, 13, 16, and 17
d. No changes were made to that estimated range.

/A

Chriss Exhibit 1
Docket No. E-7, Sub 1214

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Feb 18 2020

Calculation of Proposed Additional Operating Income

(1)	**($000)**	McManeus Exhibit 1 Page 1	Operating Income Before Increase	$	835,370
(2)	**($000)**	McManeus Exhibit 1 Page 1	Adjusted Operating Income After Increase	$	1,175,655
(3)	**($000)**	**(2) - (1)**	Additional Operating Income	$	340,285
(4)	**(%)**	**(3) / (1)**	Additional Operating Income		40.7%

/A

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/A

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Calculation of Revenue Requirement Impact of DEC's Proposed ROE vs. Current ROE

(1)	McManeus Exhibit 1 Page 1	DEC requested rate of return			7.58%
		1) Calculate Rate of Return Using ROE = 9.9% and Equity Ratio = 52%			
		Capital Component	**Percentage of Total**	**Cost**	**Weighted Cost**
(2)	McManeus Exhibit 1 Page 2	Long Term Debt	48.00%	4.51%	2.16%
(3)		Member's Equity	52.00%	9.90%	5.15%
(4)	(2)+(3)	**Rate of Return (ROE = 9.9% and Equity Ratio = 52%)**			**7.31%**
		2) Calculate Revenue Requirement Impact at the Proposed ROE			
(5)	McManeus Exhibit 1 Page 2	Rate Base ($000)			$ 15,512,620
(6)	= (4)	Rate of Return (ROE = 9.9% and Equity Ratio = 52%)			7.31%
(7)	(5) x (6)	Adjusted Income Requirement (ROE = 9.9% and Equity Ratio = 52%)			$ 1,134,407
(8)	Commercial Group Exh. CR-1	DEC Proposed Income Requirement ($000)			$ 1,175,655
(9)	(8) - (7)	Difference in Income Requirement ($000)			$ 41,248
(10)	McManeus Exhibit 1 Page 2	Conversion Factor			1.3087
(11)	(9) x (10)	**Difference in Revenue Requirement ($000)**			**$ 53,981**
(12)	McManeus Exhibit 1 Page 1	Requested Revenue Requirement Increase ($000)			$ 445,331
(13)	(11) / (12)	**Percent of Increase from ROE Increase**			**12.12%**

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Feb 18 2020

Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
Washington	Avista Corp.	UE-150204	9.90%	1/6/2016	V	9.50%	(40)
Arkansas	Entergy Arkansas Inc.	15-015-U	10.20%	2/23/2016	V	9.75%	(45)
Indiana	Indianapolis Power & Light Co.	44576	10.93%	3/16/2016	V	9.85%	(108)
Massachusetts	Fitchburg Gas & Electric Light	15-80	10.25%	4/29/2016	D	9.80%	(45)
Maryland	Baltimore Gas and Electric Co.	9406	10.60%	6/3/2016	D	9.75%	(85)
New Mexico	El Paso Electric Co.	15-00127-UT	9.95%	6/8/2016	V	9.48%	(47)
New York	NY State Electric & Gas Corp.	15-E-0283	10.06%	6/15/2016	D	9.00%	(106)
New York	Rochester Gas & Electric Corp.	15-E-0285	10.06%	6/15/2016	D	9.00%	(106)
Indiana	Northern Indiana Public Service Co.	44688	10.75%	7/18/2016	V	9.98%	(77)
Tennessee	Kingsport Power Company	16-00001	10.66%	8/9/2016	V	9.85%	(81)
Arizona	UNS Electric Inc.	E-04204A-15-0142		8/18/2016	V		
			9.50%			9.50%	-
New Jersey	Atlantic City Electric Co.	ER-16030252	10.60%	8/24/2016	D	9.75%	(85)
Washington	PacifiCorp	UE-152253	9.50%	9/1/2016	V	9.50%	-
Michigan	Upper Peninsula Power Co.	U-17895	10.75%	9/8/2016	V	10.00%	(75)
New Mexico	Public Service Co. of NM	15-00127-UT	10.50%	9/28/2016	V	9.58%	(92)
Massachusetts	Massachusetts Electric Co.	15-155	10.50%	9/30/2016	D	9.90%	(60)
Wisconsin	Madison Gas and Electric Co.	3270-UR-121	10.20%	11/9/2016	V	9.80%	(40)
Oklahoma	Public Service Company of OK	PUD 201500208	10.50%	11/10/2016	V	9.50%	(100)
Maryland	Potomac Electric Power Co.	9418	10.60%	11/15/2016	D	9.55%	(105)
Wisconsin	Wisconsin Power and Light Co	6680-UR-120	10.00%	11/18/2016	V	10.00%	-
Florida	Florida Power & Light Co.	160021-EI	11.50%	11/29/2016	V	10.55%	(95)
California	Liberty Utilities CalPeco	A15-05-008	10.50%	12/1/2016	V	10.00%	(50)
Illinois	Ameren Illinois	16-0262	8.64%	12/6/2016	D	8.64%	-
Illinois	Commonwealth Edison Co.	16-0259	8.64%	12/6/2016	D	8.64%	-
South Carolina	Duke Energy Progress Inc.	2016-227-E	10.75%	12/7/2016	V	10.10%	(65)
New Jersey	Jersey Central Power & Light Co.	ER-16040383	11.20%	12/12/2016	D	9.60%	(160)
Connecticut	United Illuminating Co.	16-06-04	9.92%	12/14/2016	D	9.10%	(82)
Colorado	Black Hills Colorado Electric	16AL-0326E	9.83%	12/19/2016	V	9.37%	(46)
Maine	Emera Maine	2015-00360	10.25%	12/19/2016	D	9.00%	(125)
North Carolina	Virginia Electric & Power Co.	E-22 Sub 532	10.50%	12/22/2016	V	9.90%	(60)
Nevada	Sierra Pacific Power Co.	16-06006	10.26%	12/22/2016	V	9.60%	(66)
Idaho	Avista Corp.	AVU-E-16-03	9.90%	12/28/2016	V	9.50%	(40)
Wyoming	MDU Resources Group Inc.	2004-117-ER-16	10.10%	1/18/2017	V	9.45%	(65)
New York	Consolidated Edison Co. of NY	16-E-0060	9.75%	1/24/2017	D	9.00%	(75)
Michigan	DTE Electric Co.	U-18014	10.50%	1/31/2017	V	10.10%	(40)
Maryland	Delmarva Power & Light Co.	9424	10.60%	2/15/2017	D	9.60%	(100)
New Jersey	Rockland Electric Company	ER-16050428	10.20%	2/22/2017	D	9.60%	(60)
Arizona	Tucson Electric Power Co.	E-01933A-15-0322		2/24/2017	V		
			10.35%			9.75%	(60)
Michigan	Consumers Energy Co.	U-17990	10.70%	2/28/2017	V	10.10%	(60)
Minnesota	Otter Tail Power Co.	E-017/GR-15-1033		3/2/2017	V		
			10.05%			9.41%	(64)
Oklahoma	Oklahoma Gas & Electric Co.	PUD 201500273	10.25%	3/20/2017	V	9.50%	(75)
Florida	Gulf Power Co.	160186-EI	11.00%	4/4/2017	V	10.25%	(75)
New Hampshire	Liberty Utilities Granite St	DE-16-383	10.30%	4/12/2017	D	9.40%	(90)
New Hampshire	Unitil Energy Systems Inc.	DE-16-384	10.30%	4/20/2017	D	9.50%	(80)
Missouri	Kansas City Power & Light	ER-2016-0285	9.90%	5/3/2017	V	9.50%	(40)
Minnesota	Northern States Power Co.	E-022/GR-15-826	10.00%	5/11/2017	V	9.20%	(80)
Arkansas	Oklahoma Gas & Electric Co.	16-052-U	10.25%	5/18/2017	V	9.50%	(75)
Delaware	Delmarva Power & Light Co.	16-0649	10.60%	5/23/2017	D	9.70%	(90)
North Dakota	MDU Resources Group Inc.	PU-16-666	10.00%	6/16/2017	V	9.65%	(35)
Kentucky	Kentucky Utilities Co.	2016-00370	10.23%	6/22/2017	V	9.70%	(53)
Kentucky	Louisville Gas & Electric Co.	2016-00371	10.23%	6/22/2017	V	9.70%	(53)
District of Columbia	Potomac Electric Power Co.	FC-1139	10.60%	7/24/2017	D	9.50%	(110)
Arizona	Arizona Public Service Co.	E-01345A-16-0036		8/15/2017	V		
			10.50%			10.00%	(50)
New Jersey	Atlantic City Electric Co.	ER-17030308	10.10%	9/22/2017	D	9.60%	(50)

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Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
Texas	Oncor Electric Delivery Co.	46957	10.25%	9/28/2017	D	9.80%	(45)
Maryland	Potomac Electric Power Co.	9443	10.10%	10/20/2017	D	9.50%	(60)
California	Pacific Gas & Electric Co.	Advice No. 5148-E	10.25%	10/26/2017	V	10.25%	-
California	San Diego Gas & Electric Co.	Advice No. 3120-E	10.20%	10/26/2017	V	10.20%	-
California	Southern California Edison Co.	Advice No. 3665-E	10.30%	10/26/2017	V	10.30%	-
Florida	Tampa Electric Co.	20170210-EI	N/A Ω	11/6/2017	V	10.25%	N/A
Alaska	Alaska Electric Light Power	U-16-086	13.80%	11/15/2017	V	11.95%	(185)
Massachusetts	NSTAR Electric Co.	17-05	10.50%	11/30/2017	D	10.00%	(50)
Massachusetts	Western Massachusetts Electric	17-05	10.50%	11/30/2017	D	10.00%	(50)
Washington	Puget Sound Energy Inc.	UE-170033	9.80%	12/5/2017	V	9.50%	(30)
Illinois	Ameren Illinois	17-0197	8.40%	12/6/2017	D	8.40%	-
Illinois	Commonwealth Edison Co.	17-0196	8.40%	12/6/2017	D	8.40%	-
Wisconsin	Northern States Power Co. - WI	4220-UR-123	10.00%	12/7/2017	V	9.80%	(20)
Texas	El Paso Electric Co.	46831	10.50%	12/14/2017	V	9.65%	(85)
Texas	Southwestern Electric Power Co.	46449	10.00%	12/14/2017	V	9.60%	(40)
Oregon	Portland General Electric Co.	UE 319	9.75%	12/18/2017	V	9.50%	(25)
New Mexico	Public Service Co. of NM	16-00276-UT	10.13%	12/20/2017	V	9.58%	(55)
Idaho	Avista Corp.	AVU-E-17-01	9.90%	12/28/2017	V	9.50%	(40)
Nevada	Nevada Power Co.	17-06003	10.10%	12/29/2017	V	9.50%	(60)
Vermont	Green Mountain Power Corp	17-3112-INV	9.50%	12/21/2017	V	9.10%	(40)
Kentucky	Kentucky Power Co.	2017-00179	10.31%	1/18/2018	V	9.70%	(61)
Oklahoma	Public Service Co. of OK	PUD 201700151	10.00%	1/31/2018	V	9.30%	(70)
Iowa	Interstate Power & Light Co.	RPU-2017-0001	10.57%	2/2/2018	V	9.98%	(59)
North Carolina	Duke Energy Progress Inc.	E-2, Sub 1142	10.75%	2/23/2018	V	9.90%	(85)
Minnesota	ALLETE (Minnesota Power)	E-015/GR-16-664	10.15%	3/12/2018	V	9.25%	(90)
New York	Niagara Mohawk Power Corp.	17-E-0238	9.79%	3/15/2018	D	9.00%	(79)
Michigan	Consumers Energy Co.	U-18322	10.50%	3/29/2018	V	10.00%	(50)
Connecticut	Connecticut Light and Power	17-10-46	10.50%	4/18/2018	D	9.25%	(125)
Michigan	DTE Electric Co.	U-18255	10.50%	4/18/2018	V	10.00%	(50)
Washington	Avista Corp.	UE-170485	9.90%	4/26/2018	V	9.50%	(40)
Indiana	Indiana Michigan Power Co.	44967	10.60%	5/30/2018	V	9.95%	(65)
Maryland	Potomac Electric Power Co.	9472	10.10%	5/31/2018	D	9.50%	(60)
New York	Central Hudson Gas & Electric	17-E-0459	9.50%	6/14/2018	D	8.80%	(70)
North Carolina	Duke Energy Carolinas LLC	E-7, Sub 1146	10.75% ‡	6/22/2018	V	9.90%	(85)
Maine	Emera Maine	2017-00198	9.50%	6/28/2018	D	9.35%	(15)
Hawaii	Hawaii Electric Light Co	2015-0170	10.60%	6/29/2018	V	9.50%	(110)
District of Columbia	Potomac Electric Power Co.	FC-1150	10.10%	8/8/2018	D	9.53%	(57)
Delaware	Delmarva Power & Light Co.	17-0977	10.10%	8/21/2018	D	9.70%	(40)
Rhode Island	Narragansett Electric Co.	4770 (electric)	10.10%	8/24/2018	D	9.28%	(82)
New Mexico	Southwestern Public Service Co	17-00255-UT	10.25%	9/5/2018	V	9.10%	(115)
Wisconsin	Wisconsin Power and Light Co	6680-UR-121 (Elec)	10.00%	9/14/2018	V	10.00%	-
Wisconsin	Madison Gas and Electric Co.	3270-UR-122 (Elec)	9.80%	9/20/2018	V	9.80%	-
North Dakota	Otter Tail Power Co.	PU-17-398	10.30%	9/26/2018	V	9.77%	(53)
Ohio	Dayton Power and Light Co.	15-1830-EL-AIR	10.50%	9/26/2018	D	9.999% *	(50)
Kansas	Westar Energy Inc.	18-WSEE-328-RTS	9.85%	9/27/2018	V	9.30%	(55)
Pennsylvania	UGI Utilities Inc.	R-2017-2640058	11.25%	10/4/2018	D	9.85%	(140)
New Jersey	Public Service Electric Gas	ER18010029	10.30%	10/29/2018	D	9.60%	(70)
Indiana	Indianapolis Power & Light Co.	45029	10.32%	10/31/2018	V	9.99%	(33)
Illinois	Ameren Illinois	18-0807	8.69%	11/1/2018	D	8.69%	-
Illinois	Commonwealth Edison Co.	18-0808	8.69%	12/4/2018	D	8.69%	-
Kansas	Kansas City Power & Light	18-KCPE-480-RTS	9.85%	12/13/2018	V	9.30%	(55)
Oregon	Portland General Electric Co.	UE-335	9.50%	12/14/2018	V	9.50%	-
Ohio	Duke Energy Ohio Inc.	17-0032-EL-AIR	10.40%	12/19/2018	D	9.84%	(56)
Texas	Texas-New Mexico Power Co.	48401	10.50%	12/20/2018	D	9.65%	(85)
Wisconsin	Madison Gas and Electric Co.	3270-UR-122 (Elec)	9.80%	12/20/2018	V	9.80%	-
Vermont	Green Mountain Power Corp.	18-0974-TF	9.30%	12/21/2018	D	9.30%	-
Michigan	Consumers Energy Co.	U-20134	10.75%	1/9/2019	V	10.00%	(75)
West Virginia	Appalachian Power Co.	18-0646-E-42T	10.22%	2/27/2019	V	9.75%	(47)

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Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
New Jersey	Atlantic City Electric Co.	ER18080925	10.10%	3/13/2019	D	9.60%	(50)
New York	Orange & Rockland Utilities Inc.	18-E-0067	9.75%	3/14/2019	D	9.00%	(75)
Oklahoma	Public Service Company of OK	PUD201800097	10.30%	3/14/2019	V	9.40%	(90)
Maryland	Potomac Edison Co.	9490	10.80%	3/22/2019	D	9.65%	(115)
Kentucky	Kentucky Utilities Co.	2018-00294	10.42%	4/30/2019	V	9.73%	(69)
Kentucky	Louisville Gas & Electric Co.	2018-00295	10.42%	4/30/2019	V	9.73%	(69)
South Carolina	Duke Energy Carolinas LLC	2018-319-E	10.50%	5/1/2019	V	9.50%	(100)
Michigan	DTE Electric Co.	U-20162	10.50%	5/2/2019	V	10.00%	(50)
South Carolina	Duke Energy Progress LLC	2018-318-E	10.50%	5/8/2019	V	9.50%	(100)
South Dakota	Otter Tail Power Co.	EL18-021	10.30%	5/14/2019	V	8.75%	(155)
Hawaii	Maui Electric Company Ltd	2017-0150	10.60%	5/16/2019	V	9.50%	(110)
Michigan	Upper Peninsula Power Co.	U-20276	10.50%	5/23/2019	V	9.90%	(60)
Maryland	Potomac Electric Power Co.	9602	10.30%	8/12/2019	D	9.60%	(70)
Vermont	Green Mountain Power Corp.	19-1932-TF	9.16%	8/29/2019	V	9.06%	(10)
Wisconsin	Northern States Power Co - WI	4220-UR-124	N/A Ω	9/4/2019	V	10.00%	N/A
Massachusetts	Massachusetts Electric Co.	DPU-18-150	10.50%	9/30/2019	D	9.60%	(90)
Montana	Northwestern Corp.	D2018.2.12	10.65%	10/29/2019	V	9.65%	(100)
Wisconsin	Wisconsin Electric Power Co.	05-UR-109	10.35%	10/31/2019	V	10.00%	(35)
Wisconsin	Wisconsin Public Service Corp.	6690-UR-126	10.35%	10/31/2019	V	10.00%	(35)
Louisiana	Entergy New Orleans LLC	UD-18-07	10.50%	11/7/2019	V	9.35%	(115)
Idaho	Avista Corp.	AVU-E-19-04	9.90%	11/29/2019	V	9.50%	(40)
Illinois	Commonwealth Edison Co.	19-0387	8.91%	12/4/2019	D	8.91%	-
Indiana	Northern Indiana Public Service Co.	45159	10.80%	12/4/2019	V	9.75%	(105)
Illinois	Ameren Illinois	19-0436	8.91%	12/16/2019	D	8.91%	-
Georgia	Georgia Power Co.	42516	10.90%	12/17/2019	V	10.50%	(40)
Maryland	Baltimore Gas and Electric Co.	9610	10.30%	12/17/2019	D	9.70%	(60)
California	Pacific Gas & Electric Co.	A-19-04-015	12.00%	12/19/2019	V	10.25%	(175)
California	San Diego Gas & Electric Co.	A-19-04-017	12.38%	12/19/2019	V	10.20%	(218)
California	Southern California Edison Co.	A-19-04-014	11.45%	12/19/2019	V	10.30%	(115)
Arkansas	Southwestern Electric Power Co.	19-008-U	10.50%	12/20/2019	V	9.45%	(105)
Nevada	Sierra Pacific Power Co.	19-06002	10.21%	12/24/2019	V	9.50%	(71)
Iowa	Interstate Power & Light Co.	RPU-2019-0001	10.25%	1/8/2020	V	9.50% ¥	(75)
New York	Consolidated Edison Co. of NY	19-E-0065	9.75%	1/16/2020	D	8.80%	(95)
New Jersey	Rockland Electric Company	ER19050552	9.60%	1/22/2020	D	9.50%	(10)
Michigan	Indiana Michigan Power Co.	U-20359	10.50%	1/23/2020	V	9.86%	(64)
California	PacifiCorp	A-18-04-002	10.60%	2/6/2020	V	10.00%	(60)
Entire Period							
# of Decisions		**148**					
Average (All Utilities)			**10.24%**			**9.61%**	**(62)**
Average (Distribution Only)			**10.00%**			**9.37%**	**(64)**
Average (Vertically Integrated Only)			**10.37%**			**9.75%**	**(62)**
Median			**10.26%**			**9.60%**	
Minimum			**8.40%**			**8.40%**	
Maximum			**13.80%**			**11.95%**	
North Carolina		**3**	**10.67%**			**9.90%**	**(77)**
2016							
# of Decisions		**32**					
Average (All Utilities)			**10.25%**			**9.60%**	**(65)**
Average (Distribution Only)			**10.11%**			**9.31%**	**(80)**
Average (Distribution Only, exc. IL FRP)			**10.40%**			**9.45%**	**(96)**
Average (Vertically Integrated Only)			**10.33%**			**9.77%**	**(56)**
2017							
# of Decisions		**42**					
Average (All Utilities)			**10.22%**			**9.68%**	**(54)**
Average (Distribution Only)			**10.04%**			**9.43%**	**(61)**

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Reported Authorized Returns on Equity, Electric Utility Rate Cases Completed, 2016 to Present

State	Utility	Docket	Proposed Return on Equity	Decision Date	Vertically Integrated (V)/Distribution (D)	Approved Return on Equity (%)	Reduction from Proposed (BP)
Average (Distribution Only, exc. IL FRP)			**10.34%**			**9.61%**	**(73)**
Average (Vertically Integrated Only)			**10.31%**			**9.80%**	**(50)**
2018							
# of Decisions		**36**					
Average (All Utilities)			**10.10%**			**9.54%**	**(56)**
Average (Distribution Only)			**9.96%**			**9.38%**	**(58)**
Average (Distribution Only, exc. IL FRP)			**10.14%**			**9.47%**	**(66)**
Average (Vertically Integrated Only)			**10.22%**			**9.68%**	**(54)**
2019							
# of Decisions		**33**					
Average (All Utilities)			**10.43%**			**9.64%**	**(79)**
Average (Distribution Only)			**9.95%**			**9.37%**	**(57)**
Average (Distribution Only, exc. IL FRP)			**10.29%**			**9.53%**	**(77)**
Average (Vertically Integrated Only)			**10.59%**			**9.73%**	**(86)**
2020							
# of Decisions		**5**					
Average (All Utilities)			**10.14%**			**9.53%**	**(61)**
Average (Distribution Only)			**9.68%**			**9.15%**	**(53)**
Average (Vertically Integrated Only)			**10.45%**			**9.74%**	**(71)**

Source: S&P Global Market Intelligence
Last Updated: 2/8/2020
*** Due to Rounding, the ROE Award is reported as 10.00 on the S&P Global Website.**
‡ S&P incorrectly reports this value as 9.9%
Ω Utility did not file a full rate case, approved ROE based on a settlement
¥ S&P incorrectly reports this value as 10.02%

/A

Chriss Exhibit 4
Docket No. E-7, Sub 1214

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Calculation of Revenue Requirement Impact of DEC's Proposed ROE vs. National Average ROE for Vertically Integrated Utilities

(1)	McManeus Exhibit 1 Page 1	DEC requested rate of return				7.58%
		1) Calculate Rate of Return Using ROE = 9.75%				
		Capital Component	**Percentage of Total**	**Cost**		**Weighted Cost**
(2)	McManeus Exhibit 1 Page 2	Long Term Debt	47.00%	4.51%		2.12%
(3)		Member's Equity	53.00%	9.75%		5.17%
(4)	(2)+(3)	**Rate of Return (ROE = 9.75%)**				**7.29%**
		2) Calculate Revenue Requirement Impact at the Proposed ROE vs. National Average				
(5)	McManeus Exhibit 1 Page 2	Rate Base ($000)			$	15,512,620
(6)	= (4)	Rate of Return (ROE = 9.75%)				7.29%
(7)	(5) x (6)	Adjusted Income Requirement (ROE = 9.75%)			$	1,130,410
(8)	Commercial Group Exh. CR-1	DEC Proposed Income Requirement ($000)			$	1,175,655
(9)	(8) - (7)	Difference in Income Requirement ($000)			$	45,245
(10)	McManeus Exhibit 1 Page 2	Conversion Factor				1.3087
(11)	(9) x (10)	**Difference in Revenue Requirement ($000)**			**$**	**59,212**
(12)	McManeus Exhibit 1 Page 1	Requested Revenue Requirement Increase ($000)			$	445,331
(13)	(11) / (12)	**Percent of Increase from ROE Increase**				**13.30%**

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Rory McIlmoil

Senior Energy Analyst
Appalachian Voices

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Profile

Mr. McIlmoil has a background in environmental science and policy with a focus on the analysis and presentation of scientific and economic data relevant to environmental policy and energy development. He has twelve years of experience working on energy and economic policy issues in Appalachia and the Southeast. Over the past seven years, Mr. McIlmoil has been advocating for, and supporting the development of inclusive on-bill energy efficiency finance programs through rural electric cooperatives in North Carolina and Tennessee. His current areas of focus include utility regulation and rate reform, electricity markets and renewable energy policy.

Skills and Experience

Analyzing the impact on electricity bills and household energy burdens for low-income residents resulting from proposed changes in electricity rates.

Combining utility data on energy use and county property tax data to identify the seasonal and average household energy intensity (energy use per square foot of living space) of individual households to assist Appalachian Electric Cooperative in identifying priority targets for its "U-SAVE Advantage" inclusive on-bill energy efficiency finance program.

Leading on policy and technical work for an emerging bi-partisan effort to restructure North Carolina's electricity market and eliminate monopoly electric utilities.

Leading voice and researcher for the advancement of an Energy Efficiency Resource Standard through the Duke University Nicholas School for the Environment "Energy Efficiency Roadmap" project for North Carolina.

Assessing and advocating for appropriate electric utility rate structures that protect low-income residents and facilitate end-user energy efficiency and renewable energy investments.

Leading efforts to promote and help develop "inclusive" on-bill finance home energy efficiency finance programs through rural electric cooperatives in Appalachian North Carolina and Tennessee.

Leading collaborative efforts on issues related to rural electric cooperatives through the Advancing Equity and Opportunity in the Southeast Collaborative and the North Carolina On-Bill Working Group.

Developing a business model and financing plan for community-owned solar projects in Morgantown and Alderson, West Virginia.

Conducting research and analysis of the influences on demand for Central Appalachian coal and the impacts of changes in demand on local economies across the region.

Overseeing reporting and analysis of commercial energy audits.

Analyzing tax revenue data to assess the distribution of wealth generated by coal industry activity in West Virginia.

Analyzing the fiscal impact of coal-related activities for the states of West Virginia, Virginia, Tennessee, and Pennsylvania.

Characterizing distributed energy potential for Kentucky and associated economic and environmental benefits.

Projecting future economic investment that would result from a permanent mineral trust fund in West Virginia.

Education

M.A., Global Environmental Policy, American University, Washington, D.C., 2007.

B.S., Earth & Environmental Sciences, Furman University, Greenville, South Carolina, 2002.

Publications

McIlmoil. 2017. Inclusive Energy Efficiency Financing for Members of the French Broad Electric Membership Corp. Appalachian Voices.

McIlmoil. 2014. Poverty and Electricity Costs in the Southeast: The Case for Utility Home Energy Efficiency Loan and Tariff Programs. Appalachian Voices.

McIlmoil. 2013. The Continuing Decline in Demand for Central Appalachian Coal: Market and Regulatory Influences. Downstream Strategies.

McIlmoil R, Askins N, Clingerman J. 2012. The opportunities for distributed renewable energy in Kentucky. Downstream Strategies.

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Boettner T, Kriesky J, McIlmoil R. 2012. Creating an economic diversification trust fund: turning nonrenewable natural resources into sustainable wealth for West Virginia. W.Va. Center on Budget and Policy.

McIlmoil R, Hansen E, Boettner T, Miller P. 2010. The impact of coal on the West Virginia state budget. Downstream Strategies and W.Va. Center on Budget and Policy.

Presentations

Boone (NC) Town Council. 2020. "Recommendations for Achieving 100% Clean Energy in Boone."

Jefferson County (TN) "GIS Day." 2019. New Market, TN. "Using GIS and Data Analysis to Enhance Energy Efficiency Investments and Program Uptake."

ACEEE Rural Energy Conference. 2018. Atlanta, GA. "Identifying Priority Households for Pay-As-You-Save® Energy Efficiency Investments in East Tennessee."

Appalachian State University, Socioeconomic Forum. 2018. Boone, NC. "Energy Efficiency as a Public Need: Addressing Energy Waste to Alleviate Poverty, Improve Public Health, and Grow Local Economies."

Tennessee Renewable Energy and Economic Development Council, Annual Conference. 2017. Cookeville, TN. "Equity in Energy Efficiency Investments."

North Carolina State Energy Conference. 2016. Raleigh, NC. "Energy Access in Hard-to-Reach Markets: Using On-Bill Programs for Energy Efficiency Investment."

Appalachian State University, Appalachian Energy Center CLE Course, Presenter. Boone, NC. 2015. "Emerging Financial Models and Policy Structures Supporting Renewables and Energy Efficiency."

National Governor's Association, Tennessee Energy Efficiency Retreat. 2014. Nashville, TN. "Program Options and Considerations for Electric Cooperative On-Bill Energy Efficiency Finance Programs in Tennessee."

Tennessee Electric Cooperative Association, Quarterly Managers Meeting. 2013. Nashville, TN. "On-Bill Financing for Residential Energy Efficiency in Tennessee."

References

Jennifer Weiss, Sr. Policy Associate
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Duke University
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Dr. Holmes Hummel, Founder
Clean Energy Works
Former Sr. Policy Advisor, US Department of Energy
Washington, DC
phone: (510) 917-2151
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Evan Hansen, President
Downstream Strategies
Morgantown, WV
phone: (304) 292-2450
email: ehansen@downstreamstrategies.com

Other References available upon request

I/A

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Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-7, Sub 1214

February 18, 2020

Exhibit JMV-TF-1

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BACKGROUND AND QUALIFICATIONS
JAMES M. VAN NOSTRAND

Q. Please state your name, title and employer.

A. My name is James M. Van Nostrand. I am an Energy Policy Expert for EQ Research, a consulting firm based out of Cary, North Carolina. I am also a Professor of Law at the West Virginia University College of Law, where I teach energy and environmental law and Direct the Center for Energy and Sustainable Development.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. I received my B.A. degree in economics from the University of Northern Iowa in 1976 and a law degree from the University of Iowa in 1979. While I was employed at the New York Public Service Commission, I studied economics at SUNY Albany, and received an M.A. in economics in 1984 from that institution. I received an LL.M. degree in environmental law from the Elisabeth Haub School of Law at Pace University in 2011.

From 1980 to 1985, I worked for the New York Public Service Commission, first as an Assistant to the Commission for Opinions and Review and then as Assistant to Chairman Paul L. Gioia. In 1985, I joined the law firm of Perkins Coie in its Bellevue, Washington office, where I worked for 14 years, becoming a partner in 1990. In 1999, I joined the Seattle office of the Portland, Oregon-based law firm of Stoel Rives, as a partner in the firm's energy and telecommunications group. I rejoined Perkins Coie in 2006, as a partner in the firm's environmental and natural resources practice group in its Portland, Oregon office. Beginning in 2007, I transitioned into law school teaching, which included appointments to the adjunct faculty at Lewis & Clark Law School (Spring 2007), and visiting professor positions at the University of Tennessee College of Law (Fall 2007) and the University of Iowa College of Law (Spring 2008). In May 2008, I joined the adjunct faculty at Pace Law School and became Executive Director of the Pace Energy and Climate Center, an energy and environmental research and policy organization active in

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administrative proceedings in New York and the Northeast. In July 2011, I joined the faculty at the West Virginia University College of Law, and became Director of the newly established Center for Energy and Sustainable Development. Most recently, I served as a Senior Policy Advisor to Chairman John R. Rhodes of the New York Public Service Commission (on a part-time consulting basis) from January 2018 through June 2019.

Q. Have you previously testified before utility regulatory agencies?

A. Yes, I have testified in the following cases:

New York Public Service Commission: Niagara Mohawk Power Corporation, Case 10-E-0050 (testimony on behalf of Pace Energy & Climate Center, Natural Resources Defense Council on non-wires alternatives (including distributed generation and energy efficiency) and decoupling)

Colorado Public Utility Commission:

- In the Matter of Commission Consideration of Public Service Company of Colorado's Plan in Compliance with House Bill 10-1365, "Clean Air-Clean Jobs Act," Docket No. 10M 245E (testimony on behalf of Noble Energy, Inc., Chesapeake Energy Corporation and Encana Oil & Gas (USA) regarding foreseeable requirements of Clean Air Act)
- In the Matter of the Application of Public Service Company of Colorado for Approval of its Solar*Connect Program, Proceeding No. 16A-0055E, (testimony on behalf of the Energy Freedom Coalition of America)
- Public Service Company of Colorado: In the Matter of the Application for Approval of the 600 MW Rush Creek Wind Project Pursuant to Rule 3660(h) Certificate of Public Convenience and necessity for the Rush Creek Wind Farm, and a Certificate of Public Convenience and Necessity for the 345 kV Rush Creek to Missile Site Generation Tie Transmission Line and Associated Findings of Noise and Magnetic Field Reasonableness, Proceeding No. 16A-0117E (testimony on behalf of Sustainable Power Group, LLC (sPower))

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Hawaii Public Utility Commission: In the Matter of the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, and NextEra Energy Inc. for Approval of the Proposed Change of Control and Related Matters, Docket No. 2015-0022 (testimony on behalf of the Alliance for Solar Choice (TASC) in opposition to proposed merger)

South Carolina Public Service Commission: Petition of the Office of Regulatory Staff to Establish Generic Proceeding Pursuant to the Distributed Energy Resource Program Act, Act No. 236 of 2014, Ratification No. 241, Senate Bill No. 1189, Docket No. 2014-24-E (testimony on behalf of TASC)

West Virginia Public Service Commission: Appalachian Power Company and Wheeling Power Company, both dba American Electric Power, Petition for Consent and Approval of Mitchell Plant by Wheeling Power Company, Case No. 14-0546-E-PC (testimony on behalf of Consumer Advocate Division regarding the environmental liabilities associated with the Conner Run coal ash impoundment)

Q. Have you previously testified before the North Carolina Utilities Commission ("the Commission")?

A. No.

Q. In addition to cases in which you have testified, have you participated in regulatory cases as an attorney?

A. Yes, during my 22 years in private law practice in the Pacific Northwest, I represented investor-owned utilities in dozens of rate proceedings before state utility regulatory agencies in Washington, Oregon, Idaho, Wyoming, California, Utah, and Alaska. My clients included Puget Sound Energy, PacifiCorp (including Pacific Power & Light and Utah Power), Northwest Natural Gas, Cascade Natural Gas, and Portland General Electric. I also represented Puget Sound Energy in a transmission rate proceeding before the Federal Energy Regulatory Commission. In addition to rate proceedings, I handled the regulatory approvals for several utility mergers and acquisitions, including Macquarie's acquisition of Puget Sound Energy, MidAmerican Energy Holdings Company's acquisition of

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PacifiCorp, MDU Utilities' acquisition of Cascade Natural Gas Company, ScottishPower's acquisition of PacifiCorp, Qwest's acquisition of US WEST, and Puget Sound Power & Light Company's acquisition of Washington Natural Gas Company. In recognition of my achievements as an energy attorney in private practice, I received the Energy Bar Association's State Regulatory Practitioner of the Year Award in 2007. Following my transition into law school teaching, I was also involved in proceedings on behalf of Pace and Natural Resources Defense Council in proceedings before the New York Public Service Commission while I was Executive Director of the Pace Energy & Climate Center.

A copy of my current curriculum vitae is attached.

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James M. Van Nostrand

West Virginia University College of Law
P.O. Box 6130
Morgantown, WV 26506-6130
(304) 293-4694 (Office)
E-Mail: james.vannostrand@mail.wvu.edu

Current Position

Professor of Law
Director, Center for Energy and Sustainable Development July 2011 – present
West Virginia University College of Law

The Center for Energy and Sustainable Development conducts objective, unbiased research and policy analyses; provides a forum for issues to be explored by the various stakeholders; and promotes policies that strike a balance between the development of energy resources and protection of the environment.

Keyes & Fox LLP January 2016 – December 2017; July 2019 - present

Of Counsel with a national law firm specializing in distributed generation and renewable energy law, with offices in Oakland, CA, Cary, NC and Denver, CO.

EQ Research LLC January 2015 – December 2017; July 2019 - present

Energy Policy Expert on renewables and distributed energy resources for North Carolina-based consulting firm.

Prior Employment Experience

Consultant on Energy Policy (New York) January 2018 – June 2019
Van Nostrand Energy & Environmental Consulting LLC

Under consulting agreement with the New York State Energy and Research Development Authority (NYSERDA), served as Senior Policy Advisor to Chairman John B. Rhodes of the New York Public Service Commission

Executive Director May 2008 – July 2011
Pace Energy and Climate Center
Elisabeth Haub School of Law at Pace University

Executive Director of multi-disciplinary research, policy and advocacy organization focused on energy and sustainability issues and climate change law and policy; the Center is active in energy and sustainability policy matters in New York and throughout the Northeast; the Center combines objective, unbiased research and legal and policy analysis with effective advocacy in achieving necessary market and regulatory reforms supportive of renewable energy, energy efficiency and clean distributed generation.

Perkins Coie LLP

Bellevue, WA office October 1985 – November 1999
Portland, OR office July 2006 – February 2009

Partner (associate prior to January 1990) in the energy and regulatory practice in Northwest's largest law firm; practice emphasis on electricity and gas regulation, utility mergers and acquisitions, telecommunications and administrative law; recipient of ***Energy Bar Association 2007 State Regulatory Practitioner of the Year***; included in "The Best Lawyers in America" (Wood/White, 10th, 11th, 12th and 13th editions)

Clients/Representative Transactions: PacifiCorp retail rate proceedings (WA); Puget Sound Energy transmission rate proceeding (FERC), retail rate proceedings (WA); Portland General Electric retail rate proceedings (OR); Northwest Natural Gas Co. retail rate proceedings (WA and OR); Cascade Natural Gas Co. retail rate proceedings

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(WA and OR); regulatory approval for Macquarie acquisition of Puget Sound Energy (WA); regulatory approval for MDU Resources Group acquisition of Cascade Natural Gas Co. (WA and OR); regulatory approval for ScottishPower acquisition of PacifiCorp (WA, OR, ID, UT, CA, and WY); regulatory approval for Qwest acquisition of U S WEST (WA); regulatory approval for merger of Puget Sound Power & Light Company and Washington Natural Gas Company to form Puget Sound Energy (WA).

Stoel Rives LLP, Seattle and Portland offices November 1999 – July 2006

Partner in the Energy & Telecommunications practice group, with practice emphasis on electricity and gas regulation, utility mergers and acquisitions, telecommunications and administrative law

Clients/Representative Transactions: PacifiCorp retail rate proceedings (WA, OR, ID, CA, UT and WY); Portland General Electric retail rate proceedings (OR); Northwest Natural Gas Company retail rate proceedings (OR); Cascade Natural Gas Company retail rate proceedings (OR); regulatory approval for MidAmerican Energy Holding Company acquisition of PacifiCorp (WA and ID).

New York Public Service Commission, Albany, New York July 1980 – September 1985

Assistant to the Commission for Opinions and Review (3 ½ years); Assistant to the Chairman (1 ½ years); legal and policy analysis, opinion-writing for commissioners, Chairman in utility rate cases

Education

LL.M., Environmental Law (Climate Change Track), Elisabeth Haub School of Law at Pace University (2011)

M.A., Economics, State University of New York at Albany (1985)

J.D., University of Iowa College of Law (With High Honors) (1979)
Order of the Coif; Class Rank 9/201
Associate editor, *Journal of Corporation Law*

B.A., Economics, University of Northern Iowa (With Highest Honors) (1976)

Teaching Experience

West Virginia University College of Law, Morgantown, WV – Professor, July 2016 to Present (Associate Professor, July 2011 to July 2016) – Teach various energy and environmental courses (Energy Regulation, Markets & the Environment, Science & Technology of Energy, Siting and Permitting of Energy Facilities, Environmental Protection Law, Alternative Energy & Renewable Fuels, Clean Air Act Seminar, Legislation & Regulation)

University of Pittsburgh School of Law, Pittsburgh, PA – Adjunct Faculty, Spring 2015 and Spring 2016 – Taught Environmental Law

University of Iowa College of Law, Iowa City, IA – Visiting Professor, Spring 2008 – Taught courses in Energy Law & Regulated Industries, Administrative Law

University of Tennessee College of Law, Knoxville, TN – Visiting Professor, Clayton Center for Entrepreneurial Law, Fall 2007 – Taught courses in Energy Law & Regulated Industries, Business Associations

Lewis & Clark Law School, Portland, OR – Adjunct Faculty, Spring 2007, taught 3-credit course in Energy Law and Economic Regulation of Utilities

Willamette University, Atkinson Graduate School of Management, Utility Management Certificate Program – Assisted in developing curriculum for MBA-level program for utility managers; instructor, 2005 to Present

Northeast Bioenergy and Bioproducts Master Teaching Training Workshop, Pace University, New York, NY – Lecturer on Renewable Energy and Biofuels, July 2011

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Publications

"The Trump Administration's Futile Efforts to Prop Up the Declining U.S. Coal Industry," Trends, American Bar Association Section on Environment, Energy & Resources (Oct/Nov 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," 35 FLA. S. U. J. LAND USE & ENVTL. L. 1 (2020)

Using Emergency Powers to Provide Financial Assistance to Coal and Nuclear Plants," 11 KY. J. EQUINE, AGRIC. & NAT. RESOURCES L. 191 (2019)

"Protecting Consumers via Tariff Regulation," Chapter 60, ELGAR ENCYCLOPEDIA OF ENVIRONMENTAL LAW, VOLUME: ENERGY LAW AND THE ENVIRONMENT, International Union for Conservation of Nature (IUCN), Edward Elgar Publishing (to be published Spring 2020)

"Production and Delivery of Bioenergy Fuels," LEGAL PATHWAYS TO DEEP DECARBONIZATION IN THE UNITED STATES, (edited by Michael B. Gerrard and John C. Dernbach), Environmental Law Institute (2018)

"Here's Why Trump's New Strategy to Keep Ailing Coal and Nuclear Plants Makes No Sense," The Conversation (June 2018) (republished in several newspapers throughout the country)

"To Draw Jobs, WV Needs Ability to Give Manufacturers a Break on Electricity," (Op-Ed piece) CHARLESTON GAZETTE-MAIL (April 29, 2018)

"Planned Sale of Pleasants Plant a Step Backward," (Op-Ed piece) CHARLESTON GAZETTE-MAIL (September 23, 2017)

"Keeping the Fox from Managing the Henhouse: Why Incumbent Utilities Should Not Be Allowed to Operate the Distribution System Platform," 8 GEO. WASH. J. ENERGY AND ENVTL. L. 23 (2017)

"Why the U.S. Coal Industry and Its Jobs Are Not Coming Back," YALE ENVIRONMENT 360 (December 1, 2016)

"Expanding Economic Opportunities for West Virginia under the Clean Power Plan," July 2016 (with E. Hansen & J. James)

"Thinking it Through," WVU MAGAZINE, West Virginia University (Fall 2015)

"Keeping the Lights on During Superstorm Sandy: Climate Change Adaptation and the Resiliency Benefits of Distributed Generation," 23 N.Y.U. ENVTL. L.J. 92 (2015)

"Getting to Utility 2.0: Rebooting the Retail Electric Utility in the U.S.," 6 SAN DIEGO J. CLIMATE & ENERGY L. 149 (2015)

"The Clean Power Plan and West Virginia: Compliance Options and New Economic Opportunities," June 2015 (with B. Argetsinger, E. Hansen & J. James)

"Carbon Dioxide Emission Reduction Opportunities for the West Virginia Power Sector," Discussion Paper, October 2014 (with B. Argetsinger, E. Hansen, J. Simcoe)

"EPA Regulation of Carbon Dioxide Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act," written materials to accompany presentation at 2014 Kentucky Mineral Law Conference, Energy & Mineral Law Foundation

"What's Coming Down the Tracks for Midstream Operators in 2014? Emerging Issues and Regulatory Update for Crude Oil by Rail," chapter for proceedings of 35th Annual Institute, Energy & Mineral Law Foundation

"Cogeneration (CHP) Could Stimulate Demand for natural Gas Throughout Region," Bowles Rice LLP VIEWS AND VISIONS, Summer 2014

"An Energy and Sustainability Roadmap for West Virginia," 115 W. VA. L. REV. 885 (2013)

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"Energy and Environmental Justice: How States Can Integrate Environmental Justice into Energy-Related Proceedings," 61 CATH. U. L. REV. 701 (2012)

Chapter 19, "Biofuels", THE LAW OF CLEAN ENERGY: EFFICIENCY AND RENEWABLES, edited by Michael B. Gerrard, American Bar Association, 2011 (with A. Hirschberger).

"Parametric Insurance: Using Objective Measures to Address the Impacts of Natural Disasters and Climate Change," 23 ENVTL. CLAIMS J. 227, (2011) (with J. Nevius)

"Implications of a Federal RPS: Will It Supplement or Supplant the Existing State Initiatives?" 41 U. TOLEDO L. REV. 853 (2010) (with A. Hirschberger)

"Legal Issues in Financing Energy Efficiency," 2 GEO. WASH. J. ENERGY AND ENVTL. L. 1 (2011)

"New York's Roadmap for Reducing Greenhouse Gases in the Transportation Sector," 2011 U. ILL. L. REV. 475 (2011) (with A. Hirschberger).

"Preserving the Public Interest through Alternative Dispute Resolution of Utility Retail Rate Cases," 27 PACE ENVTL. L. REV. 227 (2009) (with E. Honaker)

"Constitutional Limitations on the Ability of States to Rehabilitate Their Failed Electric Utility Restructuring Plans," 31 SEATTLE U. L. REV. 593 (2008)

"Representing the Utility in State Retail Rate Proceedings," *The Best Practices of Leading Energy Lawyers: Successful Strategies and Best Practices for Dealing with Energy-Related Legal Issues*, Aspatore, Inc. (2007)

"The Standard for Setting Utility Rates in Wyoming: Restoring the Required Balance Between Investors and Customers," 4 WYO. L. REV. 245 (2004)

Co-Editor-In-Chief, *Washington Administrative Law Practice Manual*, Butterworth

"The Legislative Evolution of Title I of the Public Utilities Regulatory Policies Act of 1978: A Study in Compromise," 5 J. CORP. L 105 (1979)

"Betterment Accounting: A Requiem by the SEC?" 4 J. CORP. L. 213 (1978)

Conferences Organized

"Leaving No One Behind: Ensuring A Fair Transition for Workers and Communities," West Virginia Center on Climate Change, West Virginia Center on Budget and Policy, Charleston, WV (February 2020)

"Climate Change and Public Health: Addressing the Growing Crisis," West Virginia College of Law, West Virginia Center on Climate Change, Mid-Atlantic Regional Public Health Training Center, Morgantown, WV (September 2019)

"Climate Change Issues Update," West Virginia College of Law and Friends of Blackwater Allegheny Highlands Climate Change Impact Initiative, Morgantown, WV (December 2018)

"The Emerging Energy Economy for West Virginia," West Virginia College of Law and Appalachian Stewardship Foundation, Morgantown, WV (October 2017)

"Building a Resilient West Virginia: Taking Control of the Mountain State's Future," West Virginia College of Law and John D. Rockefeller IV School of Policy and Politics, Morgantown, WV (April 2016)

"The Intersection of Water & Energy: Implications of Water Protection on Energy Production," West Virginia College of Law, Morgantown, WV (April 2015)

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"Regulation of CO_2 Emissions from Power Plants: Flexibility and the Path Forward for Coal Dependent States," West Virginia University College of Law, Morgantown, WV (February 2014)

"Natural Gas as the Bridge to Sustainability and Economic Growth: Exploring Policies to Stimulate the Use of Shale Gas Resources," West Virginia University College of Law, Morgantown, WV (April 2013)

"Drilling Down on Regulatory Challenges: Balancing Preservation and Profitability in the Development of Shale Gas Resources," West Virginia University College of Law, Morgantown, WV (October 2011)

International Presentations

"Getting to Utility 2.0: Merging Technological Innovation and Capital Deployment with the Energy Market Regulatory Paradigm," IUCN Academy of Environmental Law, 12th Annual Colloquium, Universitat Rovira i Virgili, Tarragona, Catalonia, Spain (July 2014)

"Distributed Generation as a Climate Change Strategy," London Climate Change Symposium, Oxford and Cambridge University Club, London, England (June 2013)

"The Potential Role of Natural Gas in Poland's Energy Planning," Guest Lecture at Szkola Glowna Gospodarstwa Wiejskiego (SGGW), Warsaw, Poland (June 2013)

"Development Trends and Importance of Natural Gas in the Economy," Drilling Oil-Gas AGH 2013, Akademia Gorniczo-Hutnicza (AGH), Krakow, Poland (June 2013)

Two-day executive course for national stakeholders on Climate Change Law and Policy, with Professor Nicholas A. Robinson, sponsored by the Environmental Education Center of Ilia State University (Tbilisi Georgia), the Center for Environmental Legal Studies of Pace Law School, and the International Union for the Conservation of Nature (IUCN), Ilia State University Institute of Alpine Ecology, Stephantsminda, Georgia (May 2011)

"Lessons Learned From Emissions Trading Under the Northeast Regional Greenhouse Gas Initiative (RGGI)," Green Korea 2010 Conference, Seoul, South Korea (September 2010)

Testimony

"Promoting Solar on Former Mine Lands," West Virginia House of Delegates, Interim Hearing of the Energy Committee, Charleston, WV (November 2019)

EPA Public Hearing on Repealing the Clean Power Plan, Charleston, WV (November 2017)

West Virginia Public Service Commission, Public Hearing on Proposed Transfer of Pleasants Station, Case No. 17-0296-E-PC, Morgantown, WV (September 2017)

"Impacts of EPA Regulations on West Virginia's Coal Production, Employment, Air Quality, Community Wellness, Climate Risk and Local Government Operations," Testimony to U.S. Senate Committee on Environment and Public Works, Subcommittee on Clean Air and Nuclear Safety, Field Hearing, Logan, WV (October 2016)

"Regional Impacts of EPA Carbon Regulations: The Case of West Virginia," Testimony to U.S. Senate Committee on Environment and Public Works, Field Hearing, Beckley, WV (March 2015)

Testimony to West Virginia House of Delegates, Judiciary Committee, regarding HB 2001 (repeal of West Virginia Alternative and Renewable Energy Portfolio Standard) (January 2015)

"Regulatory Hurdles to Cost Recovery for Coal Plant Maintenance and Upgrades," Testimony to U.S. Senate Energy and Natural Resources Committee, Subcommittee on Public Lands, Forests and Mining, Field Hearing, Morgantown, WV (September 2013)

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Other Recent Presentations

"Recent Developments in Quantifying the Resilience Value of Distributed Energy Resources," Fourth Annual Research Roundtable on Energy Regulation, Technology, and Transaction Costs: Cross-Cutting Perspectives, Northwestern Pritzker School of Law, Northwestern Center on Law, Business, and Economics, Institute for Regulatory Law & Economics, Chicago, IL (November 2019)

"The Use of Renewable Portfolio Standards, Net-Zero Carbon Goals, and Zero Emissions Credits in Reshaping the U.S. Power Industry," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," Energy Policy Research Conference, Boise, ID (September 2019)

"Variations on Community Solar Program Design," Community Solar Power Summit, Philadelphia, PA (July 2019)

"Incorporating Solar Energy into the Appalachian Grid," Energy & Mineral Law Foundation, 40th Annual Institute, Washington, DC (June 2019)

"Solar Policy Priorities for West Virginia," West Virginia Solar United Neighbors, 4th Annual Solar Congress, Charleston, WV (April 2019)

"Quantifying the Resilience Value of Distributed Energy Resources," Panel Discussion on Energy Resilience, Florida State University, Tallahassee, FL (January 2019)

"Using Emergency Powers to Provide Financial Assistance to Coal and Nuclear Plants," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2018)

"The (Dim) Prospects for Coal's Ability to Compete in Wholesale Electricity Markets," Reed Smith LLP, Pittsburgh, PA (December 2018)

"The Impact of a Jobs First Agenda: A New Energy Economy," Community Discussion Series, Wheeling Academy of Law and Science, Wheeling, WV (October 2018)

"The Cost of Cutting the Cord: Distributed Energy Resources and Exit Fees," Energy Policy Research Conference, Deer Valley, UT (September 2017)

"Executive Powers to Set Aside the Law: Department of Energy Authority under the Federal Power Act," West Virginia College of Law, Continuing Legal Education, *Government Powers and Limitations*, Morgantown, WV (October 2017)

"Introduction to U.S. Energy Policy Making," Lecture to Shenhua Delegation, National Research Center for Coal and Energy, Morgantown, WV (August 2017)

"Protecting the Environment without an Environmental Protection Agency," Earth Day 2017, West Virginia University, Morgantown, WV (April 2017)

"Roundtable: The State of Low Carbon Technology," Reed Smith LLP, Pittsburgh, PA (February 2017)

"An Ethical, Sustainable Energy Industry—A Panel Discussion," Appalachian Public Interest Environmental Law Conference, Knoxville, TN (October 2016)

"An Ethical, Sustainable Energy Industry," Panel Discussion, Howard H. Baker Jr. Center for Public Policy, Knoxville, TN (October 2016)

"The Role of Renewable Energy and Energy Efficiency under the Clean Power Plan," Panel Presentation on "Renewables—Coming to a Grid Near You!" Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2016)

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"An Update on Energy Issues in West Virginia," West Virginia Agricultural Land Protection Authority, Davis, WV (October 2016)

"New Clean Air Standards and Sustainable Development in West Virginia," West Virginia State University, Keynote Speaker Earth Day 2016, Institute, WV (April 2016)

"Trends and Outlook for Workers in the Coal Industry and Coal-Reliant Communities," Brookings Institution and Columbia Center on Global Energy Policy Workshop, "Building a Better Future for Coal Workers and Their Communities," Washington, DC (November 2015)

"Speaking Truth to Power: West Virginia's Options for Responding to EPA's Clean Power Plan," Wheeling Jesuit University, Appalachian Institute, Wheeling, WV (October 2015)

"The. U.S. Clean Power Plan: What Are Our Options?" Allegheny Highlands Climate Change Impacts Initiative 2015 Climate Change Conference, Blackwater Falls State Park, WV (October 2015)

"EPA's Clean Power Plan: An Overview and Compliance Options for West Virginia," Rotary Club of Charleston, WV (October 2015)

"Response of the Coal-Dependent States to the Clean Power Plan: Litigate, Legislate, Retaliate or Innovate?" Pittsburgh Coal Conference, Pittsburgh, PA (October 2015)

"EPA's Clean Power Plan: An Overview and Compliance Options for West Virginia," Reed Smith Teleseminar: The Coal Industry, Pittsburgh, PA (August 2015)

"Saving Lives When the Grid Goes Down: Improving the Resilience of the Healthcare System in the Face of Extreme Weather Events," National Association of County & City Health Officials (NACCHO) Preparedness Summit, Atlanta, GA (April 2015)

"Regulation of CO_2 Emissions from Existing Power Plants under Section 111(d) of the Clean Air Act: The View from a Coal-Dependent State," Energy Finance 2015 Conference, Institute for Policy Integrity and the Institute for Energy Economics and Financial Analysis, , NYU School of Law, New York, NY (March 2015)

"(Relatively) Green and Clean: Environmental Impacts of Renewable Electricity Generating Projects," American Law Institute (ALI) CLE, Environmental Law (co-sponsored by the Environmental Law Institute (ELI)), Washington, DC (February 2015)

"Regulation of CO_2 Emissions from Existing Power Plants: The Clean Power Plan and Considerations for West Virginia," Energy Efficient West Virginia, Charleston, WV (December 2014)

Closing Remarks, "Energy for the Power of 32," Sustainable Pittsburgh, Pittsburgh, PA (December 2014)

"Utility of the Future and the Business Model under a New Regulatory Paradigm," University of San Diego School of Law, Sixth Annual Climate and Energy Law Symposium, San Diego, CA (November 2014)

"Clean Power and Carbon: A View from the States, Regulation of CO_2 Emissions from Existing Power Plants under the Clean Air Act," Energy & Mineral Law Foundation, Kentucky Mineral Law Conference, Lexington, KY (October 2014)

"Regulation of CO_2 Emissions from Existing Power Plants: The Clean Power Plan and Considerations for West Virginia," Monongahela Group of the Sierra Club and the WVU Sierra Student Coalition, Morgantown, WV (July 2014)

"What's Coming Down the Tracks for Midstream Operators in 2014? Emerging Issues and Regulatory Update for Crude Oil by Rail," Energy & Mineral Law Foundation 35th Annual Institute, White Sulphur Springs, WV (June 2014)

"Getting to Utility 2.0: The Evolution of the Energy Market Regulatory Paradigm to Accommodate the Customer-Centric Utility of the Future," Albany Law School Government Law Center and New York State Department of Public Service Symposium "An Energy Agenda for the Future," Albany, NY (May 2014)

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"Climate Change Adaptation and Electric Utility Planning: The Resiliency Benefits of Distributed Generation and Lessons from Superstorm Sandy," Ohio Legal Scholarship Workshop, Akron, OH (February 2014)

"Starting from Scratch: Promoting Energy Efficiency Without the Foundations of IRP or an EERS," American Council for an Energy-Efficient Economy (ACEEE) National Conference on Energy Efficiency as a Resource, Nashville, TN (September 2013)

"Who Has the Power? Panel Discussion/Forum on Electric Utilities in West Virginia," Wheeling Academy of Law and Science, Wheeling, WV (September 2013)

"Workshop on the Development of Unconventional Hydrocarbons in the Appalachian Basin," National Research Council, invited participant, West Virginia University, Morgantown, WV (September 2013)

"Coal and Biomass Opportunities: Energy Policies and Environmental Impacts," Conference on Coal and Biomass Opportunities, Appalachian Hardwood Center and National Research Center for Coal and Energy at West Virginia University (September 2012)

"Energy Trends in West Virginia," West Virginia Land and Mineral Owners Association Annual Meeting (May 2012)

"Integration of Environmental Issues in Electric Utility Regulatory Proceedings," Washington & Lee College of Law Energy Symposium (February 2012)

"Adaptation Strategies: Responding to Climate Change as the New 'Normal'," Annual Meeting of Association of American Law Schools (January 2012)

"The Future of Energy: A Discussion of Alternative Energy and New Technology," conference on Environmental Sustainability presented by The Sisters of the Divine Compassion, "Going Green: Moral Imperative and Balancing Act" (May 2011)

"Get Empowered: Renewable Energy Now! A Panel Discussion on Post-Fossil Fuel Energy Solutions that Preserve New York's Natural Resources," Westchester for Change (April 2011)

"The Role of Renewable Energy in the US in the 21st Century," Westchester Community College 2011 Domestic Policy Series (April 2011)

"The Fracking Equation: Natural Gas Extraction plus Clean Water," 16th Annual Tulane Law School Summit on Environmental Law and Policy: The Energy Equation (April 2011)

"Hydrofracking: The Explosive Issue of Natural Gas Drilling," Pace Law School Center for Environmental Legal Studies (April 2011)

"Future of Energy," Bedford 2020 Environmental Action Day, Bedford, NY (January 2011)

"Transforming New York's Energy System," Cornell University, ILR School, Global Labor Institute Conference on "Perspectives on the Future of Climate Protection and Economic Development in New York State," New York City (November 2010)

"Legal and Constitutional Foundation for Addressing Climate Change Issues," Constitution Day Keynote Address, Dutchess Community College (September 2010)

"Update on Policy Development at the National Level," Sixth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2010)

"Indian Point: Reliability, Economic and Environmental Considerations," New York Association for Energy Economics (July 2010)

"New York's Roadmap for Reducing Greenhouse Gases in the Transportation Sector," Second Annual Biofuels Law and Regulation Conference, University of Illinois College of Law (April 2010)

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"Implications of a Federal RPS: Will It Supplement or Supplant the Existing State Initiatives?" Climate Change and the Future of Energy, University of Toledo College of Law (March 2010)

"Legal Issues in Financing Energy Efficiency," Next Generation Energy and the Law, The George Washington University Law School (February 2010)

"Understanding Energy in 2010: RECs, CERES, and Beyond," American Law Institute/American Bar Association, co-sponsored by the Environmental Law Institute, ALI-ABA Teleseminar/Audio Webcast (December 2009)

"The Impact of the Recession and Stimulus Package on Renewable Energy Development," Fifth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2009)

"Who Will Pay: The Impact of the ACES Act on Utility Rates," ABA Annual Meeting, Section of Real Property, Trust and Estate Law, "Greenhouse Gas Emissions: Who Will Regulate, How Will It Be Done, and Who Will Pay?" Chicago, IL (July 2009)

"Northeast Regional Greenhouse Gas Initiative (RGGI) and Carbon Trading," New Jersey Association of Energy Engineers 2009 Energy Futures Forum, Union, NJ (May 2009)

"Capturing the Value of Distributed Generation for More Effective Policymaking," American Solar Energy Society, SOLAR 2009, Buffalo, NY (May 2009)

"Federal Smart Grid Initiatives," Pace Environmental Law Society Earth Week Panel: "The Smart Grid: The Legal and Logistical Impediments of Upgrading our Nation's Electricity Grid," White Plains, NY (April 2009)

"Global Warming Today: A Hot Topic in a Cold Economic Climate," ABA Section of International Law Annual Meeting, Washington, DC (April 2009)

"Small Cogen: CHP for Individual Buildings in New York City," New York Chapter of U.S. Green Building Council (January 2009)

"Nuclear Relicensing Issues: Where Do We Get the Power and at What Price?" Pace Environmental Law Review Nuclear Relicensing Symposium (October 2008)

"Emerging International Issues in Confronting Climate Change: Adaptation and Allowance Trading," American Branch of the International Law Association, International Law Weekend 2008 (October 2008)

"Distributed Energy and the Supply Side of Electricity," EPA Workshop on Energy and Environmental Sustainability in a Carbon-Constrained Society (September 2008)

"(Pipe)line Dreams: Solving the Puzzle of Energy Independence," New York Law School's "Justice Speaks" Series (September 2008)

"Update on Renewable Portfolio Standards, Tax Incentives, Other Policy Developments," Fourth Annual Conference on Renewable Energy in the Pacific Northwest, Law Seminars International, Seattle, Washington (August 2008)

"The 'Greening' of Energy Policies Through Renewable Portfolio Standards," Climate Change & Human Rights Symposium, University of Iowa College of Law (February 2008)

"The 'Greening' of America's Energy Policy," All-Campus Lecture Sponsored by the Clayton Center for Entrepreneurial Law, University of Tennessee College of Law (September 2007)

"State Regulation After the Repeal of PUHCA," Energy Bar Association Annual Meeting, Washington, D.C. (April 2006)

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I/A

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-7, Sub 1214

February 18, 2020

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BACKGROUND AND QUALIFICATIONS
TYLER FITCH

Q. Please state your name, title, and employer.

A. My name is Tyler Fitch. I am Southeast Regulatory Manager for Vote Solar.

Q. On whose behalf are you submitting this direct testimony?

A. I am submitting this testimony on behalf of Vote Solar.

Q. Please state your educational and professional experience.

A. I began work at Vote Solar in August 2018, where I conduct economic and regulatory policy research and provide expert testimony in a variety of legislative and regulatory venues nationally and across the Southeast. My analytical work has supported Vote Solar's regulatory interventions in Virginia, South Carolina, Georgia, Florida, New Orleans, Arizona, and Michigan, including work with former Vote Solar Regulatory Director Caroline Golin on grid modernization issues in the Southeast.

Prior to my work at Vote Solar, I was a Peter & Carolyn Mertz Fellow at the University of Michigan's School for Environment and Sustainability under Rosina Bierbaum, an internationally recognized leader in climate change adaptation policy and implementation. My published works include a novel community solar business model for a non-profit in Highland Park, Michigan, a review of the distribution of resilient energy infrastructure across ratepayers, and a techno-economic model of a microgrid in Beni, Democratic Republic of Congo. I received my Master's of Science from the School in May 2018.

I worked as a consultant at ICF International from 2013 to 2016, eventually serving as the technical lead for the Better Buildings Challenge's Multifamily Sector, where I oversaw energy benchmarking and wrote the program's data policy. I also hold a Bachelor of Science in Environmental Science from the University of North Carolina at Chapel Hill. My professional background is described in detail in my *curriculum vitae,* attached hereto.

Q. Have you previously testified before the North Carolina Utilities Commission ("the Commission")?

A. No.

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Tyler J. Fitch

tyler@votesolar.org
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EDUCATION

Master's of Science in Natural Resources, focus in Energy Policy. *School for the Environment and Sustainability, University of Michigan,* 2018.
Bachelor's of Science in Environmental Sciences. *University of North Carolina at Chapel Hill*, 2013.

PROFESSIONAL EXPERIENCE & RELEVANT WORK

Vote Solar. **Regulatory Manager, Southeast.** *August 2018 – Present.* Support Vote Solar's regulatory and legislative work through quantitative analysis and policy research, and expert testimony. Contributed analysis and testimony for regulatory intervention in Virginia, North Carolina, South Carolina, Georgia, Florida, New Orleans, Arizona, and Michigan since August 2018.

Environmental Defense Fund. **Climate Corps Fellow.** May – August 2017 & 2018. Quantitative analysis and comment drafting on behalf of Environmental Defense Fund and Citizens Utility Board to Illinois Power Agency's Request for Comments on the Long-Term Renewable Resources Procurement Plan (LTRRPP). Led program development on Environmental Defense Fund and the Accelerate Group's *SolarInTheCommunity.com* platform.

Southern California Edison. **Graduate Consultant.** *August – December 2016.* Assisted in market valuation study for electrification in SCE service territory.

ICF International. **Research Analyst.** *October 2013 – June 2016*. Technical & quantitative analysis for federal, state, and local energy efficiency programs. Served as Multifamily Technical Lead for the Department of Energy Better Buildings Challenge, 2015-2016. Provided quantitative support for President Barack Obama's 2015 Remarks on the Better Buildings Challenge. Led policy design and implementation for the City of Cambridge, MA's Building Energy Use Disclosure Ordinance (BEUDO).

REGULATORY & RULEMAKING PARTICIPATION

- ***Expert Testimony.*** Georgia Public Service Commission, Docket #42516. Georgia Power Rate case. December 2019.
- ***Comments Submitted.*** North Carolina Department of Environmental Quality. Submitted comments on Draft Clean Energy Plan. September 2019.
- ***Supporting Analysis.*** Florida Public Service Commission 20190061-EI. FPL SolarTogether Proposal. Supporting analysis for testimony of William M. Cox. September 2019.

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- ***Comments Submitted.*** City of New Orleans Docket No. UD-19-01. Proceeding to Establish Renewable Portfolio Standards. Submitted comments June 2019.
- ***Supporting Analysis.*** Arizona Corporation Commission Docket No. RU-00000A-18-0284. Modifications to the Commission's Energy Rules. Supporting analysis for Joint Stakeholder Proposal for New Energy Rules. June 2019.
- ***Supporting Analysis.*** Georgia Public Service Commission Docket 42310 &42311. Georgia Power Company's 2019 Integrated Resource Plan. Supporting analysis for testimony of William M. Cox. April 2019.
- ***Supporting Analysis.*** Florida Public Service Commission 20180204-EI. TECO Shared Solar Tariff. Supporting analysis and drafting for Vote Solar's Comments. April 2019.
- ***Supporting Analysis.*** South Carolina Public Service Commission No. 2018-318/9-E. Duke Energy Progress/Carolinas Rate Cases. Supporting analysis for testimony of Justin Barnes. March 2019.
- ***Supporting Analysis.*** Michigan Public Service Commission Case No. U-20162. DTE Energy Rate Case. Supporting analysis for testimony of Will Kenworthy. November 2018.
- ***Supporting Analysis.*** Virginia Electric and Power Company Case No. PUR-2018-00100. Supporting analysis for testimony of Caroline Golin. October 2018.

PUBLICATIONS

- Fitch, T. "Understanding Electric Utility Ratemaking, Rate Design, and the Value of Clean Energy." Presentation given at Southface Energy Institute, February 2019.
- Fitch, T. (2018, April) Islands of Light: Microgrids and the Public Good. *Agora Planning Journal,* 12, 74-80.
- Vanderwilde, C., Fitch, T., Mueller, E., (2018, April). Fueling a Transition: Evaluating the Feasibility of a Hybrid Renewable Microgrid in Beni, Democratic Republic of Congo, manuscript. University of Michigan School for the Environment and Sustainability.
- Fitch, T., Lenhart, A., Buchanan, C., Jeong, B. (2018, January). Get Free: Understanding the Potential for Community Solar Power in Highland Park. Dow Sustainability Fellow Report Series.
- Fitch, T., (2017, September). "How Illinois is working toward a cleaner, more equitable energy future." EDF Energy Exchange.
- Fitch, T., (2016, December). "Closing the Adoption Gap: Affordable Solar Power and Energy Justice." University of Michigan School of Natural Resources & Environment Policy Brief Series.

HONORS / AWARDS

Clean Energy Leadership Institute Fellow, 2019
Peter & Carolyn Mertz Fellow, 2018
UNLEASH Lab Climate Action Runner-up, 2018
Presenter at Sustainable Energy Transitions Initiative, 2018
University of Michigan Delegate to UNFCCC COP 23, 2017
Environmental Defense Fund Climate Corps Advocacy Fellow, 2017
Dow Sustainability Fellow, 2017
University of Michigan Academic Leadership Fellow, 2016
ICF International Project of the Year, 2016

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Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-7, Sub 1214

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conEdison

Climate Change Vulnerability Study

December 2019

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Climate Change Vulnerability Study

December 2019

In partnership with:

Lamont-Doherty Earth Observatory
COLUMBIA UNIVERSITY | EARTH INSTITUTE

With contributions from O'Neill Management Consulting, LLC, The Risk Research Group, Inc., and Jupiter Intelligence Inc.

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Executive Summary

In its 2013 rate case filing after Superstorm Sandy, Con Edison proposed $1 billion in storm hardening investments to build additional resiliency into its energy systems. Con Edison worked with a Storm Hardening and Resiliency Collaborative to recommend optimal investments for the proposed storm hardening funds, including the recommendation that Con Edison conduct a Climate Change Vulnerability Study (Study). As described by the New York State Public Service Commission, the purpose of this Study is to aid in the ongoing review of the Company's design standards and development of a risk mitigation plan.[1] Over the course of the Study, Con Edison regularly convened a stakeholder group to provide feedback, consisting of many of the same participants from the Storm Hardening and Resiliency Collaborative. The findings from the Study equip Con Edison with a better understanding of future climate change risks and strengthen the company's ability to more proactively address those risks.

This Study describes historical and projected climate changes across Con Edison's service territory, drawing on the best available science, including downscaled climate models, recent literature, and expert elicitation. Con Edison recognizes the global scientific consensus that climate change is occurring at an accelerating rate. The exact timing and magnitude of future climate change is uncertain. To account for climate uncertainty, the Study considered a range of potential climate futures reflecting both unabated and reduced greenhouse gas concentrations through time and evaluated extreme event "stress test" scenarios.

This Study evaluates present-day infrastructure, design specifications, and procedures against expected climate changes to better understand Con Edison's vulnerability to climate-driven risks. This analysis identified sea level rise, coastal storm surge, inland flooding from intense rainfall, hurricane-strength winds, and extreme heat as the most significant climate-driven risks to Con Edison's systems. Con Edison has unique energy systems, and vulnerabilities vary across those systems. The utility's electric, gas, and steam systems are all vulnerable to increased flooding and coastal storms; workers across all commodities are vulnerable to increasing temperatures; and the electric system is also vulnerable to heat events.

While Con Edison already uses a range of measures to build resilience to weather events, the vulnerabilities identified in this Study guide the company to pursue additional strategies to mitigate climate risks. The Study establishes an overarching framework that can work to strengthen Con Edison's resilience over time. While many adaptation strategies focus on avoiding impacts altogether, a comprehensive resilience plan also requires a system that can reduce and recover from impacts, particularly following outages.

Over the course of 2020, Con Edison will develop and file a Climate Change Implementation Plan, which will specify a governance structure and a strategy for implementing adaptation options over the next 5, 10, and 20 years. While this Study assesses vulnerabilities within Con Edison's present-day systems to a future climate, the implementation plan must also consider the evolving market for energy services, and potential changes to services and infrastructure driven by customers, government policy and external actions over time.

[1] Cases 13-E-0030, 13-G-0031, 13-S-0032, Order Adopting Storm Hardening and Resiliency Collaborative Phase Three Report Subject to Modifications (January 25, 2016).

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The Need for a Study

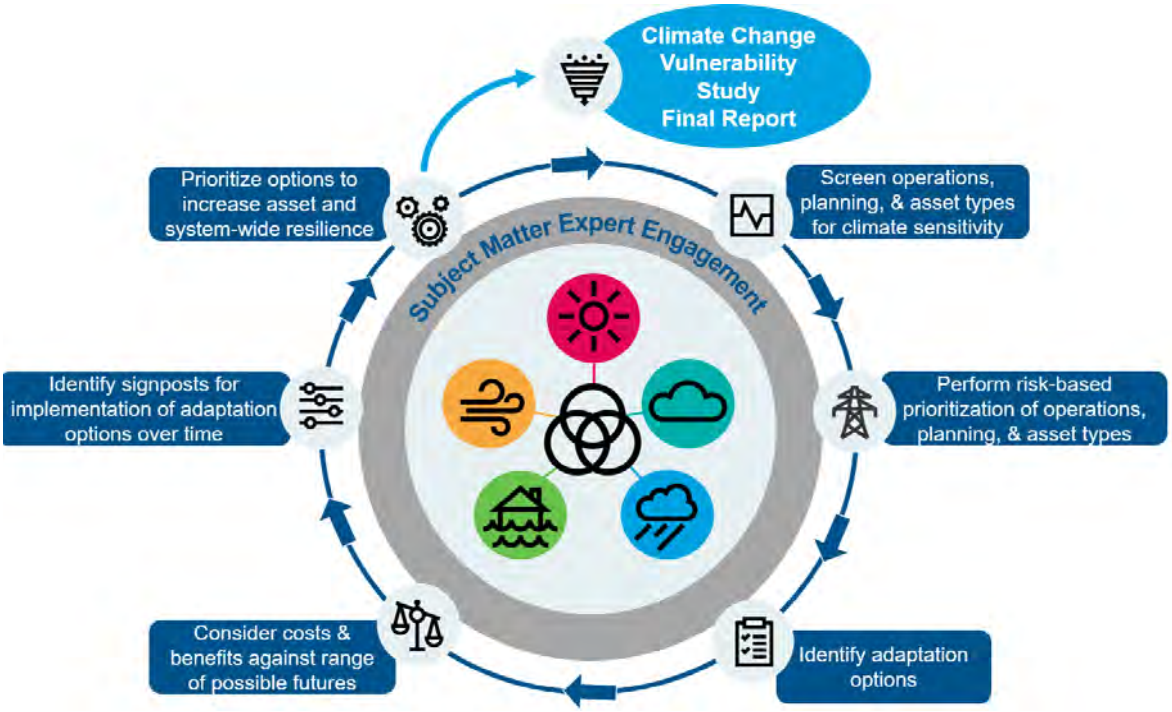
The New York State Public Service Commission approved an Order and funding for Con Edison to conduct a Climate Change Vulnerability Study, with a requirement for delivery by the end of 2019. The Con Edison Department of Strategic Planning undertook this Study with support from more than 100 subject matter experts throughout the company and in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The Study was designed to meet three primary goals:

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves.

1. Research and develop a shared understanding of new climate science and projected extreme weather for the service territory.
2. Assess the risks of potential impacts of climate change on operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study used an integrated approach to achieve these goals, as shown in Figure 1.

Figure 1 ■ General approach overview: The process cycles through the steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.



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A New Understanding of Climate Science and Extreme Weather

Con Edison will face new challenges from a rapidly changing climate through the 21st century. To better understand these challenges, the Study characterized historical and projected changes to climate hazards within the service territory to estimate the magnitude and timing of potential climate vulnerabilities. Climate variables that present outsized impacts to Con Edison include temperature, humidity, precipitation, sea level rise, and extreme events, such as rare hurricanes and long-duration heat waves.

Temperature

Average and maximum air temperatures are projected to increase throughout the century relative to historical conditions. Assuming unabated greenhouse gas concentrations, Con Edison could experience up to 23 days per year in which maximum temperatures exceed 95°F by 2050 relative to 4 days historically. Heat waves with 3 or more days when *average* temperatures exceed 86°F in Central Park are projected to occur up to 5 and 14 times per year by 2050 and 2080, respectively, relative to 1 heat wave every 5 years historically.

Humidity

The frequency of very high heat index thresholds, which combines both temperature and humidity, is projected to increase dramatically through the century. The number of days per year where the heat index equals or exceeds 103°F could increase by 7 to 26 days by 2050, compared with only 2 days historically. In addition, Con Edison evaluates the relationship of system load to an index called temperature variable (TV), which is similar to a heat index, but considers the persistence of heat and humidity over several days. Looking forward, TV thresholds that historically occur only once per year (e.g., 86°F) are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and between 5 and 52 times per year by 2080 based on reduced and unabated greenhouse gas concentrations, respectively.

Precipitation

Con Edison's service territory experiences rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types. For example, the heaviest 5-day precipitation total could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Ultimately, projections point to a future defined by more frequent heavy precipitation, likely accompanied by smaller increases in the frequency of dry or light precipitation days.

Sea Level Rise

Sea levels are very likely to rise between 0.62 and 1.94 feet by 2050. In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise increases both the frequency and height of future floods. For example, the flood height associated with the 1% annual chance flood (i.e., the so-called 100-year flood) in New York City is projected to increase from 8.3 feet to as much as 13.3 feet by 2100 relative to mean sea level at the Battery tide gauge. By the end of the century, today's annual chance flood could occur at every high tide.

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Extreme Events

Extreme events are low-probability and high-impact phenomena, such as hurricanes and long-duration heat waves. While difficult to simulate in climate models, a growing body of evidence suggests that many extreme events will increase in frequency and intensity as a result of climate warming. This Study considers high impact "worst-case"[2] extreme event scenarios, including a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter, to understand these changes and their impacts on Con Edison.

Characterization of Con Edison's Vulnerabilities to Climate Risks

Heat and Temperature Variable

The core electric vulnerabilities to increasing temperature and TV include increased asset deterioration, decreased system capacity, increased load, and decreased system reliability. Since the internal temperature of electric power equipment is determined by the ambient temperature as well as the power being delivered, higher ambient temperatures increase the internal operating temperature of equipment.

Higher internal operating temperatures increase the rate of aging of the insulation of electric equipment such as transformers, resulting in decreased total life of the assets. Higher internal temperatures, resulting from higher average and maximum ambient temperatures, also reduce the delivery capacity of electric equipment such as transformers. In addition, higher ambient temperatures increase the operating temperature of overhead transmission lines, causing increased sagging. One remedy is to decrease the operational rating of the assets to reflect the new operating environment. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system, and Con Edison will need to make investments to replace that capacity if it is needed.

Similarly, higher TV can cause higher peak loads due to increases in demand for cooling. Increases in load may also require investments in system capacity to meet the higher demand. The combination of decreased capacity and increased load is best addressed through Con Edison's existing 10- and 20-year load relief program. Addressing this combined risk is estimated to cost between $1.3 billion and $4.6 billion by 2050 (based on future projections using Representative Concentration Pathway (RCP) 4.5 10th and RCP 8.5 90th percentiles, respectively).

Increases in heat waves are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks. The Study's forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the 65 underground networks may not be able to maintain Con Edison's standard of reliability by 2050, absent adaptation.

Outdoor worker safety may be a concern across all Con Edison commodities if heat index values rise as projected. When needed, Con Edison can implement safety protocols (e.g., shift modifications and hydration breaks) already practiced in mutual aid work that the company provided in hotter locations such as Florida and Puerto Rico. Similarly, to supply sufficient cooling in 2080, Con Edison's heating, ventilation, and air conditioning (HVAC) capacity will have to increase by 11% due to projected increases in dry bulb temperature. These systems have a roughly

[2] "Worst-case" scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

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15-year life span and therefore can be upgraded during routine replacements with minimal cost increases.

Flooding from Precipitation, Sea Level Rise, and Coastal Storms

All underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from precipitation events, sea level rise, and coastal storms. Following Superstorm Sandy in 2012, Con Edison protected all infrastructure in the floodplain against future 100-year storms and 1 foot of sea level rise (e.g., submersible infrastructure, flood walls, pumps, elevation). Sea level rise projections suggest that Con Edison's 1 foot of sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

Electric substations, overhead distribution, underground distribution, and the transmission system are sensitive to precipitation-based hazards, although the design of Con Edison's assets already mitigates some of these risks. For example, flooding from increased intense precipitation can damage non-submersible electrical equipment, although Con Edison designs all underground cables and splices to operate while submerged in water. In addition, all underground distribution equipment installed in flood zones and all new installations are submersible.

To assess future asset vulnerability to sea level rise and storm surge, the Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise, while keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). Of the 324 substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. In addition, 32 gas regulators and five steam generation stations would be exposed. Hardening all of these assets would cost approximately $680 million.

Both the gas and steam distribution systems are vulnerable to water entry, which can reduce system pressure and limit distribution capacity. In the gas system, low-pressure segments[3] are particularly vulnerable to this risk. In addition, the steam system is susceptible to "water hammer" events when a high volume of water collects around a manhole, causing steam in the pipes underneath to cool and condense. Interaction between steam and the built-up condensate may cause an explosion, both damaging the steam system and putting public safety at risk.

Across all commodities, increased winter precipitation can wash salt from city roads, causing an influx of salt-saturated runoff into manholes and percolation into the ground. Salt can cause equipment degradation, arcing, manhole fires or explosions, and failure of underground assets.

Extreme and Multi-Hazard Events

The Study team reviewed the vulnerabilities of Con Edison's electric, gas and steam systems to future extreme events based on specific, worst case extreme event narratives (Category 4 hurricane, a strong nor'easter, and a prolonged heat wave) designed to stress-test these systems.

Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. In addition, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system and damage overhead distribution infrastructure, which could cause widespread customer outages.

[3] The Con Edison gas system contains piping operating at three pressures: low, medium, and high.

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An extreme nor'easter may cause significant damage to assets across all commodities. During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system.

Con Edison's systems are vulnerable to exceeding system capacity during extreme temperatures; gas systems may experience overloading during extreme cold, and electric systems during extreme heat.

On an operational level, the increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by orders of magnitude, outpacing current levels of emergency planning and preparedness.

Resilience Management Framework

A resilience management framework will help Con Edison build resilience over time.

To conceptualize how to systematically address vulnerabilities, the Study team developed a resilience management framework (Figure 2). The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual and extreme climate risks through resilience actions throughout the life cycle of the assets. As such, many adaptation strategies fall under this category. Investments to increase the capacity to withstand also provide critical co-benefits such as enhanced blue-sky functionality and reliability of Con Edison's systems. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's systems achieve better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

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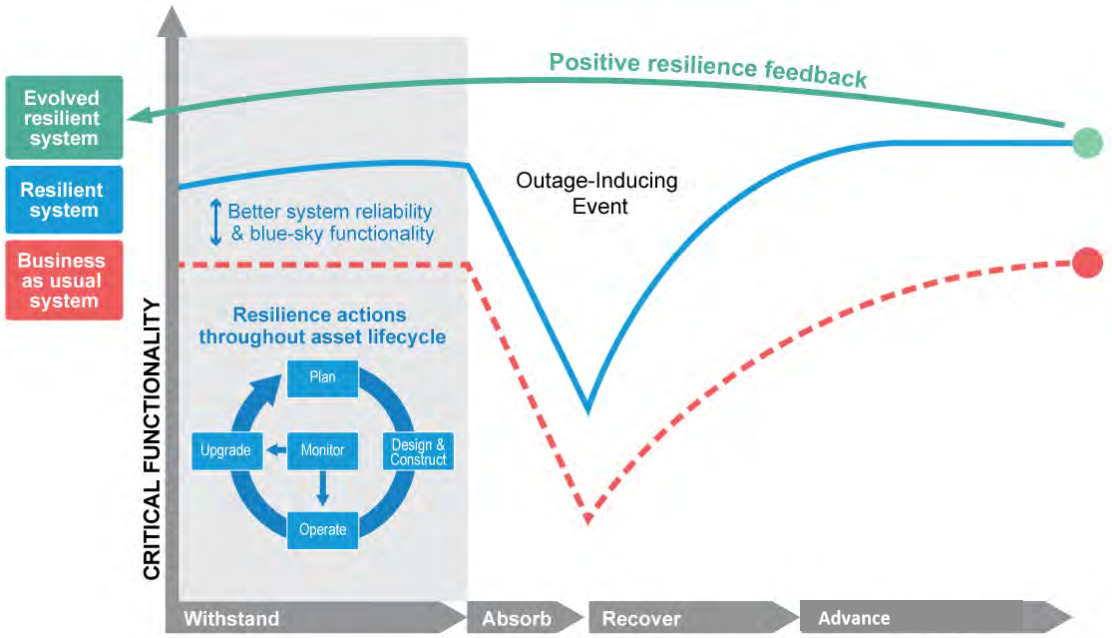
Figure 2 ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



Adaptation Measures to Address Vulnerabilities

Con Edison already has undertaken a range of measures to build resilience; this Study identified additional adaptation options to address vulnerabilities under a changing climate.

Con Edison has already undertaken a range of measures to increase the resilience of its systems. For example, lessons learned and vulnerabilities exposed during past events, including Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system. Looking forward, as Con Edison is investing in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. In addition to new investments, Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability, which help the company keep pace with recent changes in temperature and humidity.

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Withstand Gradual Changes in Climate and Extreme Events

Resilience actions should occur systematically throughout an asset's life cycle to enhance the ability to withstand changes in climate while also enhancing system reliability and blue-sky functionality. This can be accomplished through planning, designing, and upgrading assets in a resilient manner, with ongoing monitoring throughout.

Plan

Incorporating climate change projections into Con Edison's routine planning processes will help identify capital needs and help the systems gradually adjust to changes in climate. Some of the types of planning processes and tools that may benefit from consideration of climate change include the following:

- Load and volume forecasting for all commodities
- Load relief planning for the electric system, which should include reduced system capacity and higher load due to warmer temperatures
- Working with utilities in other environments to understand how they plan and design their system for the climate Con Edison will experience in the future
- Long-range planning for all commodities
- Network reliability modeling and planning

Design

The key to designing resilient infrastructure is to update design standards, specifications, and ratings to account for likely changes in climate over the life cycle of the infrastructure. While there is uncertainty as to the exact changes in climate an asset will experience, selecting an initial climate projection design pathway allows engineers to design infrastructure in line with Con Edison's risk tolerance. The Study team suggests an initial climate projection design pathway that follows the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation.

Upgrade

Changing design standards will influence the construction of new assets but does not address the vulnerability of existing assets. A flexible and adaptive approach to managing and upgrading assets will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach allows Con Edison to adjust adaptation strategies as more information about climate change and external conditions that may affect Con Edison's operations is learned over time. Figure 3 depicts how flexible adaptation pathways are based on flexible management to maintain tolerable levels of risk.

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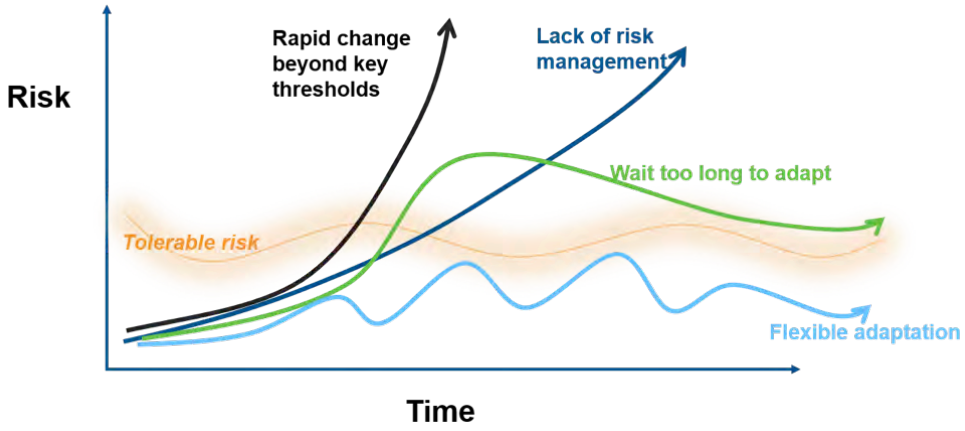
Figure 3 ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.



As conditions change over time, Con Edison will need to consistently track these changes to identify when decision making for additional or alternative adaptation strategies is required. This approach relies on monitoring indicators, or "signposts," that provide information which is critical for adaptive management decisions. Broad categories of signposts that Con Edison should consider monitoring include climate variable observations and best available climate projections; climate impacts; and policy, societal, and economic conditions. Predetermined thresholds for these conditions signal the need for a change in action, which support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. The body of this report provides many specific examples of proactive investments in resilience and their signposts; a few selected examples are provided in Table 1.

Table 1 ■ Examples of adaptation strategies to upgrade existing infrastructure and signposts to trigger action

Strategy	Signpost
Implement electric reliability strategies, such as: • Split the network into two smaller networks. • Create primary feeder loops within and between networks. • Install a distribution substation. • Incorporate distributed energy resources and non-wires solutions. • Design complex networks that consider combinations of adaptation measures.	Forward-looking network reliability index exceeds 1 per unit
Upgrade HVAC systems.	End of the existing asset's useful life
Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion.	Expanded area of precipitation-based flooding; better maps of areas at risk of current and future precipitation-based flooding
Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues.	Increased incidence of line sag; higher operating temperatures
Strategically expand program to elevate gas regulator vent line termini to include additional regulators exposed to floodplains associated with stronger storms and inland flooding.	When sea level rise exceeds 1 foot; reported or observed flooding in vicinity of asset without vent line protectors

Absorb and Recover from the Impacts of Extreme Events

It is neither efficient nor cost-effective for Con Edison to harden its systems to withstand every type of extreme event. Instead, Con Edison must use a broader suite of adaptation strategies to absorb and recover from the inevitable disruptions caused by extreme events exceeding their design

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standards. Con Edison currently incorporates "absorb" into its design and operations with, for example, a limited ability to control customer demand and shed load in extreme cases. A broader suite of strategies focuses on emergency preparedness, limiting customer impact and improving customer coping, including the following:

- Supporting the creation of resilience hubs (spaces that support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018) and have continued access to energy services)
- Using smart meters to implement targeted load shedding to limit the impact to fewer customers during extreme events
- Strengthening staff skills for streamlined emergency response
- Planning for resilient and efficient supply chains
- Coordinating extreme event preparedness plans with external stakeholders
- Incorporating low-probability events into long-term plans
- Expanding extreme heat worker safety protocols
- Examining and reporting on the levels of workers necessary to prepare for and recover from extreme climate events
- Investing in energy storage, on-site generation, and energy efficiency programs

Advance

Advancing to a better adapted, more resilient state after an outage-inducing event (i.e., building back better/stronger) begins with effective pre-planning for post-event reconstruction. Even with proactive resilience investments, events can reveal system or asset vulnerabilities. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to a continuously changing risk environment. Outage-inducing events also provide important opportunities to measure the performance of adaptation investments, helping to inform additional actions that further resilience.

Next Steps

In 2020, Con Edison will develop an implementation plan that details priority actions needed in the next 5, 10, and 20 years.

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to integrate the recommendations from this Climate Change Vulnerability Study. The implementation plan will be developed in close coordination with Con Edison SMEs and will utilize quarterly meetings with external stakeholders. The implementation plan will consider updates in climate science, finalize an initial climate design pathway, integrate that pathway into company specifications and processes based on input from subject matter experts, develop a timeline for action with associated costs and signposts, and recommend a governance structure. Some key items for consideration in the implementation plan include determining the appropriate amount of proactive investment, changes in the policy/regulatory and operating environment and the establishment of a reporting structure.

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Introduction

Study Background and Objectives

Con Edison's resilience to climate change has important implications for increasingly interconnected societal, technological, and financial systems that the company serves. Developing a shared understanding of Con Edison's vulnerability to climate change is critical to ensuring the continued strength of the company over the coming century. The Con Edison Climate Change Vulnerability Study (Study) has three primary goals:

1. Develop a shared understanding of new climate science and projected climate and extreme weather for the territory.
2. Assess the risks of potential climate change impacts on Con Edison's operations, planning, and physical assets.
3. Review a portfolio of operational, planning, and design measures, considering costs and benefits, to improve resilience to climate change.

The Study was conducted as an outcome of the 2013 rate case. In 2013, Con Edison worked with a Storm Hardening and Resiliency Collaborative in parallel with the rate case to provide parties with an opportunity to fully examine proposals for plans to protect against storms. In 2014, the New York State Public Service Commission approved an Order and funding for Con Edison to implement measures to plan for and protect its systems from the effects of climate change, including conducting a climate change vulnerability study. The Study was developed by the Con Edison Department of Strategic Planning, in collaboration with ICF's climate adaptation and resilience experts and Columbia University's Lamont-Doherty Earth Observatory. The members of this partnership are collectively referred to as the Study team. The Study team relied on inputs and expertise from Con Edison subject matter experts (SMEs), including engaging more than 100 SMEs through a series of in-person meetings, teleconferences, and workshops.

Guiding Principles

The Study used six key principles to efficiently meet its objectives and benefit Con Edison. The Study employed a decision-first and risk-based approach, applying the best available climate science to produce flexible and adaptive solutions and mitigate risks associated with climate change and extreme weather events. The Study process was transparent and interactive to ensure that it can be replicated and institutionalized.

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Decision-first approach. The Study team used a decision-first approach, which focuses on understanding the broader vulnerabilities and constraints of the system, the objectives and needs of stakeholders, and the adaptation options available, before considering the projected changes in future climate. The Study team first identified the needs of decision makers (i.e., Con Edison leadership and SMEs) and worked from there to determine information requirements based on decision goals, instead of starting by amassing as much data as possible. This approach places a higher priority on understanding the decision-making context and providing enough information to inform those decisions, which helps to prioritize near- and long-term risks and develop effective solutions despite the existence of deep uncertainties related to future climate change.

Risk-based approach. The Study team employed a risk-based approach that considers both the likelihood and the consequence of potential changes in the climate. This involves identifying a comprehensive set of plausible future climate outcomes and assessing their probability and associated impact on Con Edison's service territory. Doing so allows Con Edison to assess its vulnerability to—and to prepare for—*high-probability and low-impact*, as well as *low-probability and high-impact*, outcomes.

Best available climate science. The Study team prioritized continuous dialogues among climate scientists, climate adaptation specialists, and Con Edison SMEs to identify which climate scenarios, time periods, hazards, variables, and thresholds are important for Con Edison's operations, infrastructure, and planning. The Study team assessed multiple lines of evidence to capture historical climate conditions in the territory and employed a comprehensive set of Global Climate Models to identify the extent to which current climate conditions may change throughout the 21st century. Ultimately, the Study team synthesized climate information into metrics relating plausible effects of climatic changes on operations, infrastructure, and planning.

Transparent and replicable. A transparent and replicable approach allows Con Edison to institutionalize its adaptation strategy and increase its adaptive capacity over time. This will help SMEs establish their adaptation efforts into emerging policies and procedures, as well as train the next generation of SMEs in resilience building. Transparency also engenders trust with internal and external stakeholders.

Flexible solutions and adaptive implementation. A flexible and adaptive approach will allow Con Edison to manage risks from a changing climate at acceptable levels, despite uncertainties about future conditions. Adaptive implementation pathways, or flexible adaptation pathways, are a recognized approach to adaptation planning and project implementation that ensures adaptability over time in the face of uncertainty: changes in energy demand, technologies, population, and other driving factors, and refinements in the scientific understanding of future climate. Under the adaptive approach, resilience measures can be sequenced over time, allowing Con Edison to protect against near-term changes while leaving options open to protect against the wide range of plausible changes emerging later in the century.

Resilience management framework. The Study introduces a resilience management framework that allows Con Edison to mitigate risks associated with climate changes and extreme weather events most relevant to Con Edison's service territory (Figure 4). Resilient systems are composed of more than hardening measures alone, and instead consider measures that increase resilience throughout the life cycle of outage-inducing climate events. These measures include the system's capacity to "withstand," "absorb," and "recover" from climate risks and "advance" resilience. In this way, the resilient management framework is particularly important for addressing complex extreme

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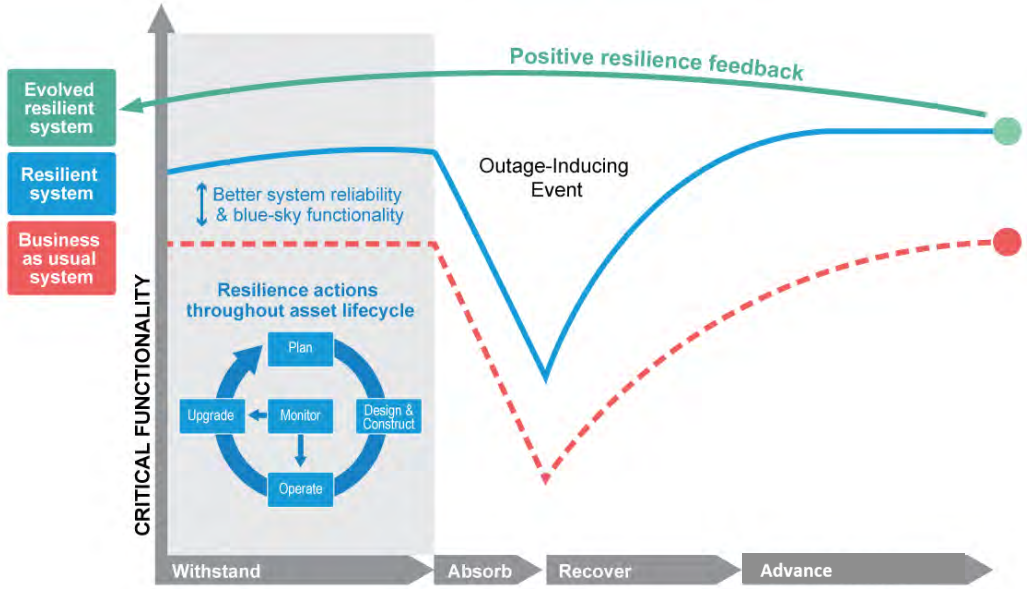
events with significant uncertainties and extreme thresholds to build into hardening measures alone. In turn, resilient systems offer critical co-benefits, such as improved system reliability and blue-sky functionality, reduced consequences from non-climatic risks, and more resilient customers. A resilience management framework also facilitates long-term adaptation, which enhances the critical functionality of the system through time and creates positive resilience feedback. To succeed, each measure of a resilient system requires proactive planning and investments.

Figure 4 ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



Study Methodology

The Study uses an integrated approach, with Con Edison SMEs providing support throughout the process. A rapid screen of the sensitivity of operations, planning, and assets (referred to for simplicity as "assets" throughout the rest of this document unless otherwise stated) for each climate change hazard provided the basis for a risk-based prioritization of assets. The Study team performed detailed analyses for the sensitive assets, including identifying a portfolio of adaptation options and qualitatively considering the financial costs, co-benefits, and resilience of each option. These detailed analyses will inform the development of flexible solutions and the further prioritization of assets and options to increase systemwide resilience during the creation of Con Edison's Climate Change Implementation Plan in 2020. Figure 5 depicts the Study's general approach.

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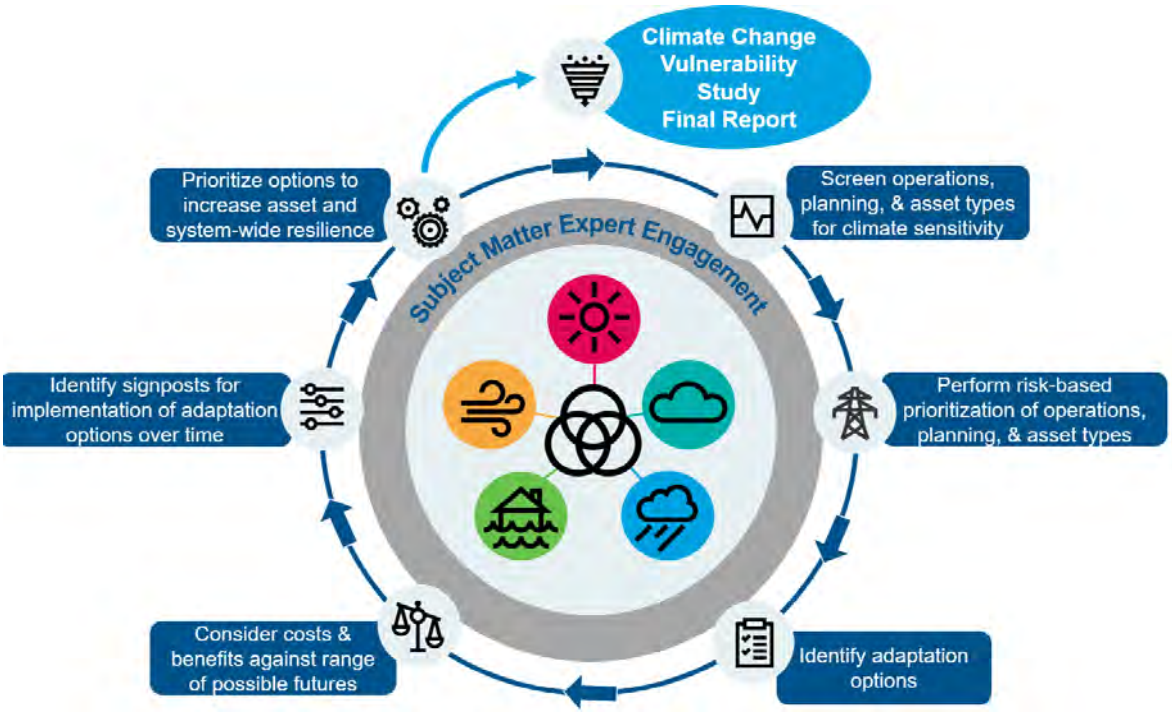
Figure 5 ■ General approach overview: The process cycles through steps for each climate hazard, beginning with 'Screen operations, planning, and asset types for climate sensitivity'. The process results in the Climate Change Vulnerability Study Final Report.



Screen operations, planning, and asset types for climate sensitivity. The Study began by establishing and confirming a clear set of climate change hazards and relevant thresholds for operations, planning, and asset types. The study team engaged SMEs to identify the extent to which each climate change hazard is a factor in asset design or operation and rate sensitivities by considering impacts from previous weather events and key climate information used in design or operation. Only assets with high sensitivity were considered in the subsequent risk-based prioritization process.

Perform risk-based prioritization of operations, planning, and asset types. Following the high-level screen for sensitivity, the Study team sought to prioritize operations, planning processes, and asset types for further analysis.

- Heat and humidity: Heat and humidity design standards vary across Con Edison assets, so the Study team used a risk workbook to guide SMEs through a structured process to identify the *probability of impact* (based on the probability of exceeding thresholds and the impact of threshold exceedance) and the *consequence of impact*. Together, these components create an *overall risk score* for each relevant asset and climate change hazard combination. *Consequence* is defined as the likely impact to the overall system given the possibility for damage or failure of the particular asset, and includes reliability, safety, environmental damage, and financial costs to the company or customers. The Study team identified several asset types and variable combinations with high sensitivity and high overall climate risk to carry forward as priorities in the analysis.
- Sea level rise and storm surge: Sea level rise and storm surge is a geographically defined hazard with a common design standard across all Con Edison assets. As such, there was a need to

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identify potentially exposed assets rather than prioritize among them. The Study team used Geographic Information System (GIS) modeling to evaluate the specific type and number of assets that would be exposed under various future scenarios.

- Precipitation: Very few of Con Edison's assets have design standards tied to precipitation. For the few that were identified, the Study team evaluated whether the assets would withstand future increases in the intensity of precipitation events. In addition, the Study team worked with Con Edison SMEs to identify and prioritize the operational impacts of precipitation on the various commodities.
- Extreme events: By definition, the extreme events analyzed in the study exceed all existing Con Edison design standards. As such, the Study team conducted a workshop with SMEs to prioritize extreme event risks based on the following:
  - The potential for impacts on operations, planning, and assets
  - How prior major weather events affected assets and operations
  - The preparations that Con Edison has in place for future extreme events
  - How longer or more intense events might overwhelm current preparedness efforts

Identify adaptation options. For the identified vulnerabilities, the Study team developed adaptation response options through SME engagement, review of relevant literature, and lessons learned from adaptation options implemented in regions with similar challenges. Adaptation options include strategies to withstand a changing climate, such as engineering design, operations, and planning strategies, as well as strategies to absorb and recover from extreme events. The Study team considered adaptation options that are often already in use to manage the hazard, but which may require revision or updating to deal with changing risk. The Study team also considered both short-term and long-term solutions and took steps to understand and assess the limitations of adaptation options.

Consider costs and benefits of adaptation options against a range of possible futures. The Study team worked with SMEs to develop order of magnitude costs of the various adaptation strategies, where feasible. Where possible, the Study team conducted a multi-criteria analysis of the adaptation options to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis.

Identify signposts for implementation of adaptation options over time. Evaluation of adaptation measures in the context of a continuously changing risk environment poses a challenge to typical project planning, design, and execution. It is important to ensure that decision-making processes support flexible solutions that allow for effective risk management in the face of irreducible uncertainties in projections of future climate conditions. The Study uses an adaptive implementation pathway approach to achieve this goal. The Study team designed a framework for "signposts," which represent information that will be tracked over time to help Con Edison understand how climate, policy, and process conditions change and, in turn, trigger additional action.

Prioritize options to increase asset and systemwide resilience. Once the prior steps were completed, the Study team circulated the findings to SMEs to allow them to strike, add, or refine strategies. This process resulted in the prioritized set of strategies included in this report.

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Historical and Future Climate

Con Edison in a Changing Climate

Earth's climate is not static; it changes in response to both natural and human-caused drivers. The past decade was the warmest on record, and global atmospheric warming has increased at a faster rate since the 1970s (GCRP, 2017), which the global climate science community attributes to increasing human-caused greenhouse gas emissions (IPCC, 2013).

A growing body of research reveals that a range of climate hazards will likely increase in frequency and intensity as a result of atmospheric warming (GCRP, 2017; IPCC, 2013). For example, a warmer atmosphere increases the frequency, intensity, and duration of heat waves; holds more water vapor for heavy precipitation events; and accelerates ice loss from Earth's large ice sheets, contributing to sea level rise and coastal storm surge. These climate changes highlight how changes in the global climate system affect local climatology and weather in Con Edison's service territory. Local changes include both long-term mean changes, such as gradual increases in temperature and sea level, and changes in extreme events, such as heat waves, hurricanes, and storm surge. In most cases, long-term climate change amplifies and increases the likelihood of extreme events. In turn, climate changes and baseline climate hazards cause both direct (e.g., physical damage to infrastructure) and indirect (e.g., changing customer behavior) impacts across the electric, gas, and steam systems of Con Edison's business.

Rapid climate change will bring new challenges to Con Edison through the 21st century. This Study develops climate projections to characterize these challenges. Still, conceptualizing climate change in tangible terms is notoriously difficult. Another way to describe potential climate change is through climate analogs, which match expected future climate change at a location to current climate conditions in another. Under this perspective, New York City's temperature and precipitation by 2080 could more closely resemble current conditions in southern cities such as Memphis, TN, and Little Rock, AR, if greenhouse gas emissions continue unabated (Fitzpatrick & Dunn, 2019).[4]

[4] Climate analogs are illustrative and vary depending on the choice of evaluation metrics, decade, and climate scenario. In this case, analogs are determined using metrics for seasonal minimum and maximum temperature and total precipitation.

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Con Edison's Understanding and Assessment of Climate Change

The Study team developed improved, downscaled climate projections and used best available science to understand and evaluate climate change trends and potential extreme weather events across Con Edison's service territory over near- (2030), intermediate- (2050), and long-term (2080) time horizons.[5] This approach builds on methods used by the New York City Panel on Climate Change (NPCC) and introduces a range of benefits (see Table 2). The Study team focused on climate variables that could present outsized impacts to operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business. These include temperature, humidity, precipitation, sea level rise and coastal flooding, extreme events, and multiple—or compounding—events.

The primary tools for understanding future climate change are Global Climate Models (GCMs), which mathematically simulate important aspects of Earth's climate, such as changes in temperature and precipitation, natural modes of climate variability (e.g., El Niño and La Niña events), and the influence of human greenhouse gas emissions (GCRP, 2017). Over short timescales (i.e., years to decades), individual GCM projections can differ from one another due to unpredictable natural climate variability, differences in how models characterize small-scale climate processes, and their response to greenhouse gas emissions/concentration assumptions. For these reasons, future climate analyses often consider a large ensemble of GCMs to better discern long-term trends, account for uncertainty, and consider a fuller range of potential future climate outcomes. To this end, the Study team used a broad model ensemble (i.e., 32 GCMs) for each climate variable of interest to address the spread across models and provide a comprehensive view of future climate.

While GCMs use a finer spatial resolution than ever before, they still provide coarse-resolution estimates of future climate, with model grid cells typically extending approximately 100 kilometers on one side. To achieve a more accurate representation of local climate in the New York Metropolitan Region, the Study team bias-corrected and downscaled GCM projections (i.e., statistically adjusted simulations to bring them closer to observed data) using weather station data over a 1976–2005 historical reference period from three weather station locations spanning Con Edison's service territory, including Central Park, LaGuardia Airport, and White Plains Airport.[6]

GCM simulations are driven by a standard set of time-dependent greenhouse gas concentration trajectories called Representative Concentration Pathways (RCPs), developed by the Intergovernmental Panel on Climate Change (IPCC). RCPs consider different evolutions of fossil fuels, technologies, population growth, and other controlling factors on greenhouse gas emissions through the 21st century. To acknowledge uncertainty in future greenhouse gas concentrations, the Study team selected the commonly used RCPs 4.5 and 8.5 to drive each GCM, following precedent set by IPCC and NPCC. RCP 4.5 represents a moderately warmer future based on a peak in global greenhouse gas emissions around 2040. In contrast, RCP 8.5 represents a hotter future

[5] Columbia University's Lamont-Doherty Earth Observatory led the analysis of temperature, humidity, and precipitation projections and extreme event information. ICF provided insights into future climate conditions using localized constructed analog (LOCA) projections, analyzed sea level rise projections, and synthesized extreme event narratives. Jupiter Intelligence provided projections of extreme temperatures and the urban heat island effect.

[6] Technical information regarding bias-correction and downscaling methods used in this Study are provided in the appendices for the relevant climate variables.

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corresponding to "business as usual" increases in greenhouse gas concentrations through the century.

The Study team used a model-based probabilistic framework to evaluate climate change hazards and account for model uncertainty under different RCP scenarios. Specifically, the Study team analyzed high-end estimates (e.g., the 90th percentile of projections across climate models), and mid-point (50th percentile) and low-end (10th percentile) projections for both RCPs. In doing so, the Study Team considered the range of potential climate outcomes across models and RCPs to form a comprehensive risk-based approach. Under this framework, the RCP 8.5 90th percentile approximates a stress test to characterize low probability, high-impact climate change, and its impact on Con Edison.

This Study builds on the approach used by NPCC. Table 2 provides a high-level overview of climate information advances developed as part of this Study.

Table 2 ■ Overview of climate projection methods in this Study relative to the NPCC2 (2015) climate projections of record for New York City

NPCC2 (Reference Projections)	Con Edison Study
Combined projections from two scenarios (RCPs 4.5 and 8.5)	Separate scenario projections
Four time periods (2020–2080)	Seven time periods (2020–2080) to align with planning processes
Single reference point (Central Park)	Multiple reference points tailored to the service territory (Central Park, White Plains, and LaGuardia)
Downscaling using the "delta method"	Downscaling using "quantile mapping"
Limited set of climate variables	Numerous Con Edison-specific variables and multi-variable projections (e.g., heat plus humidity)

The Study also evaluates Con Edison's vulnerability to rare and complex extreme events, such as major hurricanes and long-duration heat waves, that may increase in intensity and frequency as a result of climate change. Such events play an outsized role in shaping the public's perception of climate change vulnerability and how institutions should address its unique challenges. While the Study team uses model-based probabilistic projections to inform many climate variables, such as long-term mean temperatures and sea level, it is more challenging to project the rarest events, such as a 1-in-100-year heat wave, and multi-faceted and difficult to model events such as hurricanes. Obstacles to modeling rare and complex extreme events include the brevity of the historical record relative to the rarity of the event, and challenges associated with modeling extremes that have important features at very small space and time scales.

To address these challenges, the Study team constructed a series of extreme event narratives based on historical analogs and the best available climate science. In contrast with model-based

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probabilistic projections, narratives represent plausible future worst-case scenarios[7] meant to stress-test Con Edison's system. The narratives merge a decision-first and risk-based approach, blending best available science with decision maker-defined high impacts to develop a better understanding of Con Edison's vulnerability to rare, complex extreme events.

Overview of Climate Science Findings Relevant to Con Edison

The Study team's analysis characterized historical and future changes in temperature, humidity, precipitation, sea level rise, and extreme events within Con Edison's service territory. This information supports a risk-based understanding of potential climate-related vulnerabilities within the company's operations, planning, and physical assets. The sections below provide an overview of projected climate changes relevant to Con Edison. While projections were prepared for Central Park, LaGuardia, and White Plains as described above, this section commonly uses Central Park as a reference point due to its central location and because it currently serves as a reference point for many Con Edison operations. The report appendices contain detailed information on other locations and the full scope of climate projections and corresponding vulnerabilities developed for this Study.

The timing and magnitude of climate change over the coming century remains uncertain, particularly with respect to rare and multi-faceted extreme events. This uncertainty presents challenges for institutions such as Con Edison in understanding the potential effects of climate change and the associated risks to their business, operations, and financial performance.

Scenario analysis is a proven way to address these challenges. For example, Task Force on Climate-Related Financial Disclosures (TCFD) scenarios use forward-looking projections to provide a framework to help companies prepare for risks and opportunities brought about by climate change. The scenarios used in this Study are similarly hypothetical constructs, but differ from TCFD scenarios in that they provide quantitative details regarding future extreme event conditions (e.g., regarding specific storm characteristics) so that Con Edison can better plan for specific impacts to assets and infrastructure. Ultimately, this Study uses both climate science and stakeholder-driven perspectives to develop plausible, high impact worst-case scenarios designed to stress-test Con Edison's system.

Temperature

Both average and maximum air temperatures are projected to increase throughout the century relative to historical conditions (Figure 6). Climate model projections reveal significant increases in the number of days per year in which average temperatures exceed 86°F (up to 26 days per year, relative to a baseline of 2 days) and maximum temperatures exceed 95°F (up to 23 days per year from a baseline of 4 days; Figure 7) by 2050. At the same time, winter minimum temperatures are expected to fall below 50°F as many as 40 fewer times per year than in the past by mid-century, representing a 20% decrease.

[7] Worst-case scenarios are meant to explore Con Edison system vulnerabilities related to rare extreme weather events and formulate commensurate adaptation and resilience strategies. Scenarios represent one plausible permutation of extreme weather and the severity of actual events may exceed those considered.

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Figure 6 ■ Historic (black line) and projected (colored bands) average air temperature in Central Park during the summer under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5)

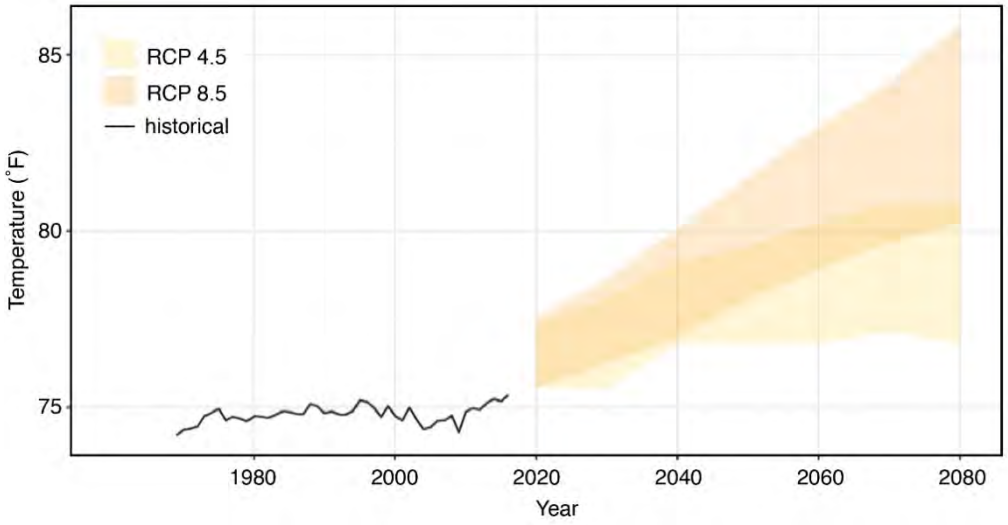
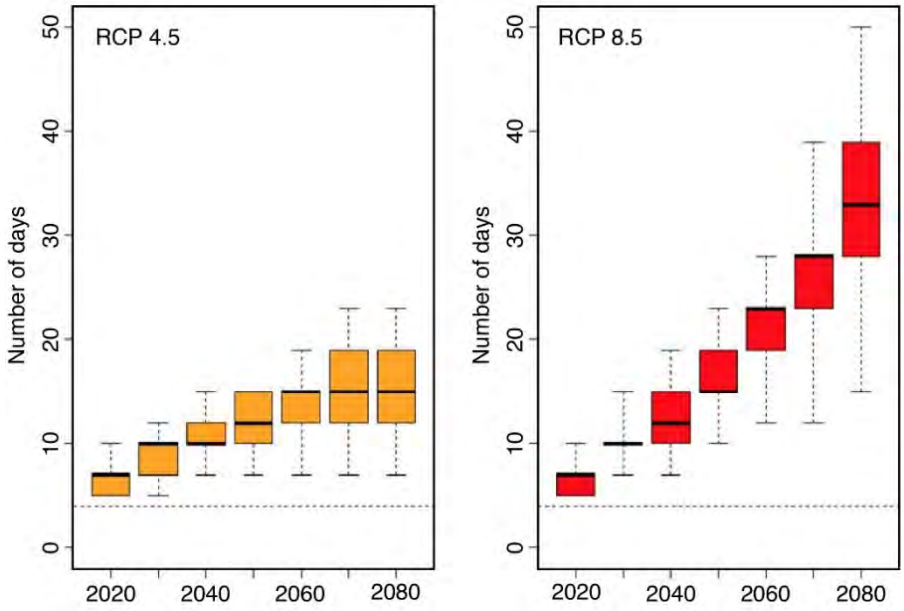


Figure 7 ■ The average number of days per year with maximum summer air temperatures exceeding 95°F in Central Park under two greenhouse gas concentration scenarios (RCPs 4.5 and 8.5). The dashed horizontal lines show the historical average number of days. Box plots correspond to the 10th, 25th, 50th, 75th, and 90th percentile projections.



Multi-day heat events, known as heat waves, create potential risks for Con Edison as they drive demand for air conditioning and stress electrical and infrastructure systems. The number of heat waves, defined here as 3 or more consecutive days when *average* temperatures exceed 86°F in Central Park, is projected to increase up to 5 and 14 events per year by 2050 and 2080, respectively, relative to 0.2 events per year historically. The magnitudes of temperature increases are projected to be greatest at LaGuardia and Central Park and smaller at White Plains.

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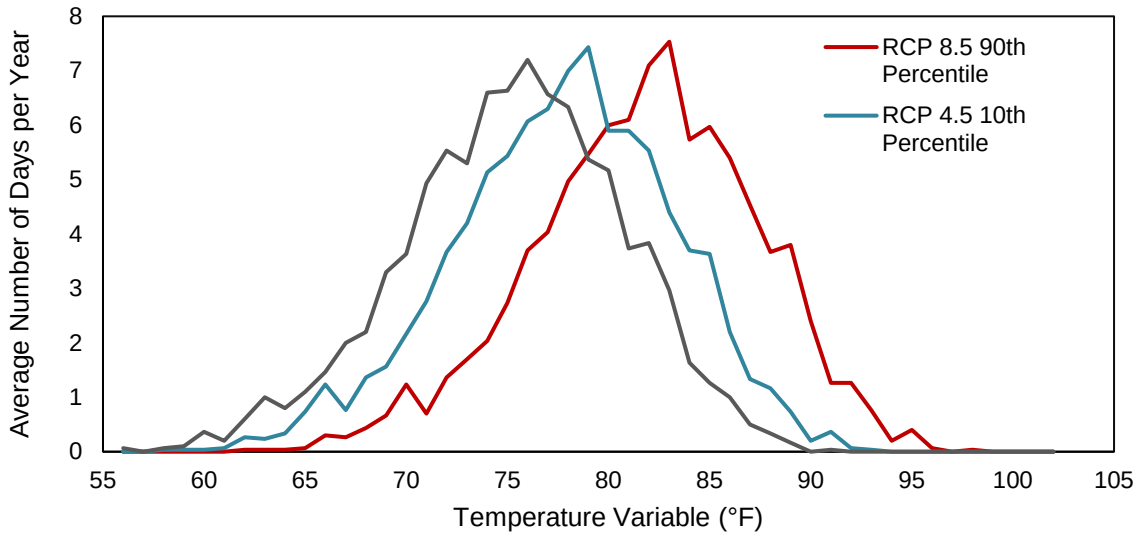
Humidity

The New York Metropolitan Region is susceptible to significant combinations of heat and humidity, which cannot be captured by temperature alone. The combination of temperature and humidity drives electric demand within Con Edison's service territory. To address this, the company currently evaluates the potential for high loads using an index referred to by Con Edison as temperature variable (TV),[8] which incorporates considerations of both temperature and humidity. Looking forward, TV thresholds that have historically occurred only once per year (e.g., 86°F), are projected to become common occurrences within a generation, occurring between 4 and 19 times per year by 2050 and 5 and 52 times per year by 2080, under the RCP 4.5 10th percentile and RCP 8.5 90th percentile, respectively, at LaGuardia (Figure 8). Smaller increases are expected at White Plains.

Figure 8 ■ Distributions showing historical (black line) and 2050 projected (blue and red lines) summer (June–August) daily electric TV at LaGuardia Airport. The 2050 projections show both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile distributions.



The heat index is a typical indicator of "how hot it feels," which considers the combined effect of air temperature and relative humidity. The index assesses health risks associated with overheating, including for Con Edison employees working under hot conditions. Looking forward, the frequency of occurrence for very high heat index thresholds is projected to increase dramatically through the century. Projections reveal that the number of days per year when the heat index equals or exceeds 103°F at LaGuardia could increase to between 7 and 26 days by 2050 under the RCP 4.5 10th percentile and the RCP 8.5 90th percentile, respectively, compared to only 2 days historically.

[8] Temperature variable is calculated using the weighted time integration of the highest daily recorded 3-hour temperature and humidity over a 3-day period. The reference TV for Con Edison is 86°F, which approximates a heat index of 105°F.

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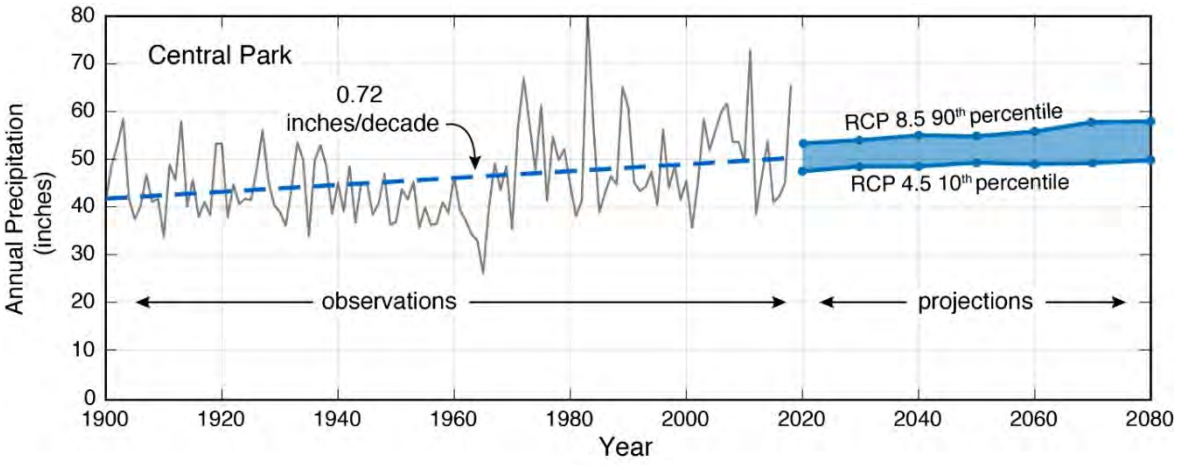
Precipitation

Con Edison's service territory experiences a range of precipitation events over a range of timescales, including rainfall, downpours, snowfall, and ice. Climate change is projected to drive heavier precipitation across these event types because a warmer atmosphere holds more water vapor and provides more energy for strong storms. Looking forward, average annual precipitation is projected to increase by 0% to 15% relative to the historical baseline in Central Park through 2050 (Figure 9).

Figure 9 ■ Observed and projected annual precipitation at Central Park. Projections show potential annual precipitation under both the RCP 8.5 90th percentile and the RCP 4.5 10th percentile. Projections represent 30-year time averages (shown as blue circles), which reveal the long-term trend, but underrepresent year-to-year variability. The dashed line represents the linear trend though the observational record, with observed increases given in inches per decade.



Projections of heavy rainfall reveal similar increases. For example, the heaviest 5-day precipitation amount could be 11.8 inches at Central Park by 2050, which represents a 17% increase over the historical reference period. Data from the Northeast Regional Climate Center[9] show that 25-year, 24-hour precipitation amounts at Central Park, LaGuardia, and White Plains could increase by 7% to 14% and 10% to 21% by mid- and late-century, respectively. Ultimately, projections point to a future defined by more frequent heavy precipitation and downpours, likely accompanied by smaller increases in the frequency of dry or light precipitation days (GCRP, 2017).

Projections for changes in snow and ice are more uncertain than those for rainfall. Overall, models project a decrease in snowstorm frequency corresponding to a warming climate (Zarzycki, 2018). However, while the likelihood of a given storm producing snow instead of rain will decrease in the future, if atmospheric conditions are cold enough to support frozen precipitation, then storms are expected to produce more snow (or ice) than during the present day (Zarzycki, 2018).

Sea Level Rise

A range of underlying factors, including thermal expansion of the ocean, the rate of ice loss from glaciers and ice sheets, atmosphere and ocean dynamics, and vertical coastline adjustments determine local sea level rise within Con Edison's service territory. State-of-the-art probabilistic

[9] http://ny-idf-projections.nrcc.cornell.edu/

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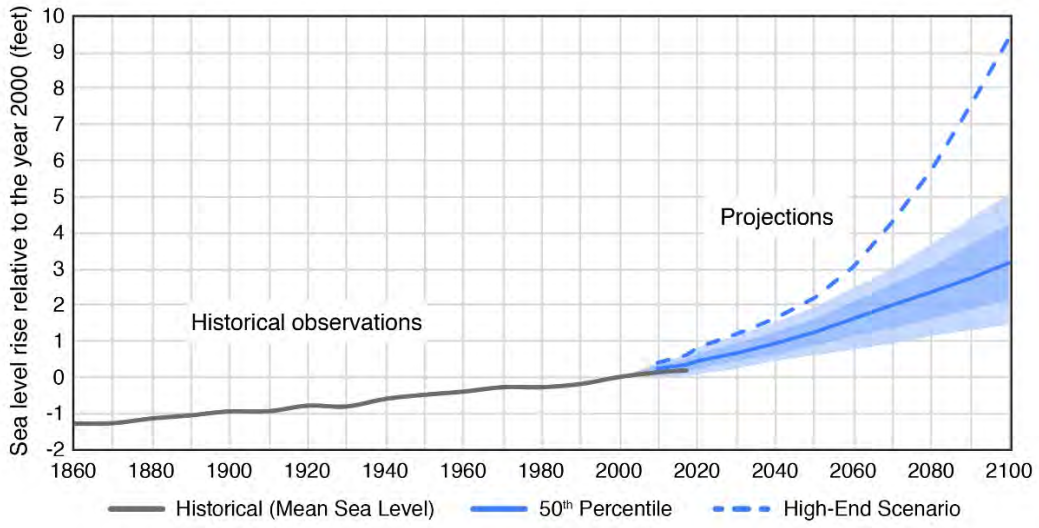
projections (Kopp et al., 2014; 2017) determined these contributions and characterized the rate of future sea level rise in the region under both RCPs 4.5 and 8.5 (e.g., Figure 10). These sea level rise projections include a unique high-end scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017). Con Edison has always implemented anti-flooding measures. Following Superstorm Sandy in 2012, the company implemented a minimum protection design standard of "FEMA plus three feet,"[10] allowing for 1 foot of sea level rise. In turn, forward-looking projections determine when sea level rise may exceed Con Edison's established risk tolerance of 1 foot of sea level rise.

Figure 10 ■ Historical and projected sea level rise in New York City under RCP 8.5 relative to the year 2000. The grey line shows historical mean sea level at the Battery tide gage. Projections are relative to the 2000 baseline year. The solid blue line shows the 50th percentile of projected sea level rise. The darker shaded area shows the likely range (17th–83rd percentiles), while the lighter shaded area shows the very likely range (5th–95th percentiles). The blue dashed line depicts a high-end projection scenario driven by rapid West Antarctic ice sheet mass loss in the later 21st century (DeConto & Pollard, 2016; Kopp et al., 2017).



Sea level rise will very likely be between 0.62 and 1.74 feet and 0.62 and 1.94 feet at the Battery tide gauge in lower Manhattan by 2050 under RCPs 4.5 and 8.5, respectively. Projections suggest that Con Edison's 1-foot sea level rise risk tolerance threshold may be exceeded as early as 2030 and as late as 2080.

In turn, rising sea levels will have profound effects on coastal flooding, as sea level rise is expected to increase both the frequency and height of future floods (Figure 11). For example, the flood height associated with the 1% annual chance (100-year) flood in New York City is projected to increase from 10.9 feet to as much as 15.9 feet under RCP 8.5 by 2100, representing an increase of close to 50%.[11] Similarly, today's 0.2% annual chance (500-year) flood could look like a 10% annual

[10] This includes the FEMA 1% annual flood hazard elevation, 1 foot of sea level rise and 2 feet of freeboard (to align with 2019 Climate Resiliency Design Guidelines published by the New York City Mayor's Office of Recovery and Resiliency).
[11] Flood values are above the mean lower low water (MLLW) datum at the Battery tide gauge. MLLW is measured as 2.57 feet below mean sea level at the Battery.

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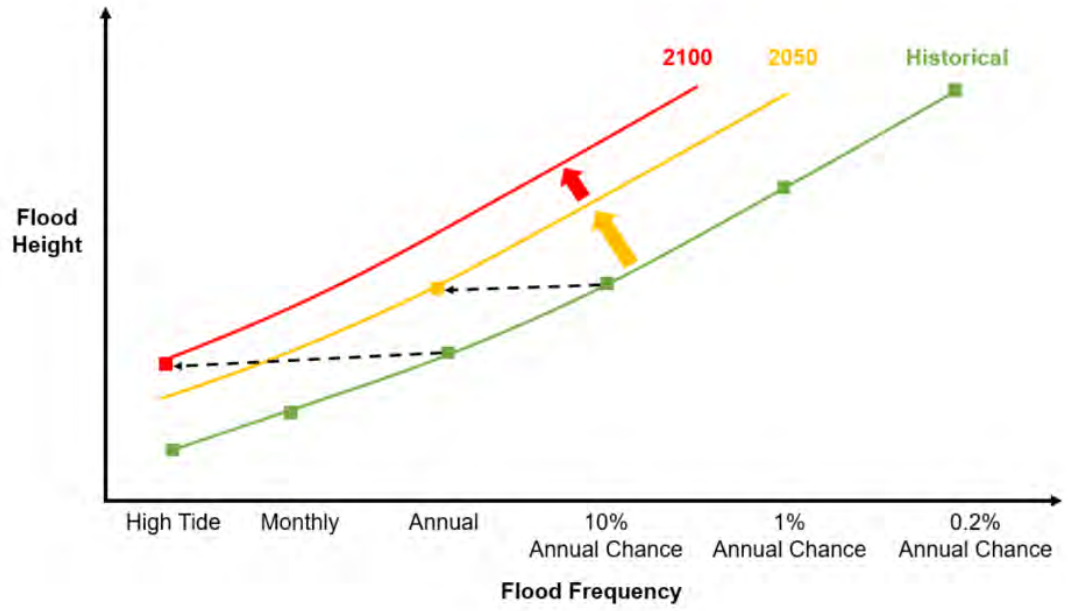
chance (10-year) flood in 2100, making it 50 times more likely. At the end of the century, today's annual chance flood could occur at every high tide.

Figure 11 ■ Projected changes in the frequencies of historical flood heights as a result of sea level rise. Dashed lines represent projected changes in frequency; solid lines represent illustrative changes in flood frequency coinciding with flood heights



Extreme Events

Rare extreme events, such as strong hurricanes and long-duration heat waves, are low-probability and high-impact phenomena that pose outsized risks to infrastructure and services across Con Edison's service territory. While modeling rare extreme events remains challenging and at the forefront of scientific research, a growing body of evidence suggests that many types of extreme events will likely increase in frequency and intensity as a result of long-term climate warming.

To address these challenges, the Study team used feedback from Con Edison SMEs to prioritize a suite of extreme event narratives that combine plausible worst-case events from both climatological and impact perspectives. In turn, the narratives represent future worst-case scenarios designed to stress-test Con Edison and the local and regional systems with which it connects. The chosen narratives considered a prolonged heat wave, a Category 4 hurricane, and an unprecedented nor'easter striking the region.

Best available climate science reveals that climate change will likely amplify these extremes over the coming century. For example, the mean heat wave duration in New York City is expected to increase to 13 and 27 days by 2050 and 2080, respectively, based on RCP 8.5 90th percentile projections (NPCC, 2019). At the same time, broadscale atmospheric and ocean surface temperature changes may drive stronger hurricanes and extratropical cyclones. Looking forward, while the total number of hurricanes occurring in the North Atlantic may not change significantly over the next century, the percentage of very strong and destructive (i.e., Categories 4 and 5) hurricanes is projected to increase in the North Atlantic basin (IPCC, 2013). It can therefore be

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argued that climate change could make it more likely for one of these storms to impact the New York Metropolitan Region, although the most dominant factor will remain unpredictable climate and weather variability (Horton & Liu, 2014). Finally, some recent studies project a 20% to 40% increase in nor'easter strengthening (i.e., producing the types of storms with destructive winds) immediately inland of the Atlantic coast by late-century, suggesting stronger storms may more frequently impact the New York Metropolitan Region with heavy precipitation, wind, and storm surge (Colle et al., 2013)

Signposts: Monitoring and Climate Science Updates

Understanding Con Edison's vulnerabilities to climate change and adapting to those changes over time require a robust monitoring strategy. Climate change evolves through time, meaning that the current spread of potential future climate outcomes produced by models will eventually converge on a smaller set of climate realizations. To keep up with this evolution, a range of signposts are required to sufficiently gauge relevant rates of change and best prepare Con Edison for the most likely climate future.

An awareness of past and present climate conditions in Con Edison's service territory is critical for understanding the trajectory of climate change. Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Increasing observations from monitoring stations will help measure both local climate variations and climate change through time, informing Con Edison's climate resilience planning. Citywide observations of variables, such as hourly temperatures, precipitation, humidity, wind speed, and sea level, are paramount to building a broad and usable set of guiding measurements. With accurate and up-to-date data on these variables, Con Edison can better monitor both changing conditions and potential points of vulnerability.

Con Edison can supplement monitoring through a regularly updated understanding of the best available projections as models and expert knowledge evolve over time. Climate projections continually improve as the scientific community better understands the physical, chemical, and biological processes governing Earth's climate and incorporates them into predictive models. Ultimately, Con Edison wants to draw on the best available data and projections that are driven by scientific consensus, but also are accessible and applicable to company needs. Signposts for updating climate science used to inform potential Con Edison vulnerabilities include major science advancements, such as the release of the new Coupled Model Intercomparison Project (CMIP) projections and their integration and validation in new IPCC, NPCC, and National Climate Assessment (NCA) reports. These assessments include updated probabilistic climate projections representing model advancements, the best available science regarding difficult-to-model extreme events, and literature reviews reflecting the current state of science as guided by leading experts. Such signposts could justify Con Edison updating their climate projections of record to reflect the best available science or projections that represent a significant departure from previous understanding. Historically, major scientific reports, such as the IPCC, have been released about every 6 to 7 years, which provide a potential constraint on how frequently Con Edison's understanding of climate change within the service territory might be revisited.

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Existing Efforts and Practices to Manage Risks Under a Changing Climate

Although this Study is Con Edison's first comprehensive assessment of climate change vulnerabilities, Con Edison has already undertaken a range of measures to increase the resiliency of its system. Lessons learned and vulnerabilities exposed during past events, most recently Superstorm Sandy (2012) and the back-to-back nor'easters (winter storms Riley and Quinn, 2018), resulted in significant capital investments to harden the system.

In addition, as Con Edison invests in the system of the future—one with greater monitoring capabilities, flexibility, and reliability—it is simultaneously building a system that is more resilient to extreme weather events and climate change. For example, grid modernization will both increase efficiency and enhance monitoring capabilities by employing new technology and modes of data acquisition. Con Edison is planning to support numerous grid modernization initiatives that target energy storage technologies, communications systems, distributed energy resources infrastructure and management, complex data processing, and advanced grid-edge sensors (Con Edison, 2019). Con Edison additionally plans to modernize its Control Center to assume more proactive and centralized management of its complex distribution grid. Throughout these modernization initiatives, the company remains in close collaboration with the City of New York.

Con Edison also conducts targeted annual updates to its system to ensure capacity and reliability. These annual updates help the company keep pace in real time with changes in some key hazards. For example, when conducting electric load relief planning, Con Edison incorporates load forecasts that use an annually updated set of TV data. Although these forecasts are not grounded in future projections that consider climate change, they do account for the most recent climate trends and, as such, allow the company to stay in stride with the most current data.

Con Edison's previous adaptation measures have made targeted improvements in (1) physical infrastructure, (2) data collection and monitoring, and (3) emergency preparedness. The following measures are illustrative of these targeted improvements, but are not meant to be exhaustive of the efforts that Con Edison has undertaken:

Physical Infrastructure

- Adopting the Dutch approach of "defense in depth" after Superstorm Sandy to protect all critical and vulnerable system components from coastal flooding risks, including the following:

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  - Upgrading and increasing the number of flood barriers and other protective structures
  - Reinforcing tunnels
  - Replacing equipment with submersible equivalents in flood zones (e.g., targeted main replacement program, gas system)
  - Installing pumps and elevating infrastructure behind flood walls
- Protecting or elevating critical electrical infrastructure to the Federal Emergency Management Agency (FEMA) 100-year flood elevation plus 3 feet to account for sea level rise and freeboard during coastal storms
- Undertaking a targeted main replacement program that addresses low-pressure gas mains in low-lying areas, as well as other potentially vulnerable gas mains
- Installing isolation devices to limit the impact of damaged infrastructure on customers by de-energizing more granular sections of the system, when necessary
- Engaging innovative technologies to reduce the impact of extreme weather on electric distribution systems and quicken the recovery, including the following:
  - Demand response technologies that more efficiently regulate load
  - Automated splicing systems that reduce feeder processing times

Data Collection and Monitoring

- Developing programs that employ machine learning and remote monitoring to identify areas of heightened vulnerability in Con Edison's systems, including the following:
  - Leak-prone areas of the gas distribution system
  - Gas system drip pots that require draining
- Initiating a more diligent inspection system that effectively assesses the functionality of assets, as well as their exposure to potential hazards (e.g., nearby vegetation), including the following:
  - Underground network transformers and protectors
  - Underground structures
  - Flushing of flood zone vaults
  - Rapid assessments of overhead feeders
  - Overhead system pole-by-pole inspection for specification compliance
- Future deployment of advanced metering infrastructure (AMI) throughout the service territory has the potential to both improve information flow to customers and help absorb the impacts of extreme events. Specifically, AMI might be able to rapidly shed load on a targeted network to help ensure demand does not exceed supply, which reduces potential damages and likelihood of network-wide outages in the event of an extreme event.

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Emergency Preparedness

- Improving contractor and material bases for post-storm repair crews and equipment, including the following:
  - Expanding and diversifying spare material inventories
  - Ensuring that all spare materials are housed in safe locations
- Conducting post-event debriefings to understand the impact of weather conditions on system performance
- Engaging with major telecommunications providers and enhancing communications systems among customer networks
- Facilitating equipment-sharing programs across New York State to ensure access to supplies during emergency response

Con Edison recognizes that the drivers behind future planning operations are inherently uncertain and is committed to both closely monitoring key signposts and continuously updating company investment plans and priorities.

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Vulnerabilities, a Resilience Management Framework, and Adaptation Options

Con Edison may face greater vulnerabilities due to future changes in temperature, humidity, precipitation, sea level rise, and extreme weather events. To understand this, the Study team evaluated key vulnerabilities of Con Edison's present-day electric, gas, and steam systems under a changing climate. The physical assets, operations, and planning of each system are uniquely vulnerable. In turn, building a detailed understanding of key vulnerabilities is an important step toward identifying priority adaptation measures.

Resilience Management Framework

Under a changing climate, Con Edison will likely experience the increasing frequency and intensity of both gradual climate changes and extreme events. In response, the Study team developed a resilience management framework (Figure 12) to outline how a comprehensive set of adaptation strategies would mitigate future climate risks. The framework encompasses investments to better withstand changes in climate, absorb impacts from outage-inducing events, recover quickly, and advance to a better state. The "withstand" component of this framework prepares for both gradual (chronic) and extreme climate risks through resilience actions throughout the life cycle of assets. As such, many of the adaptation strategies identified in the following sections fall under the category of systematically bolstering Con Edison's ability to withstand future climate risks. Investments to increase the capacity to withstand also provide critical co-benefits, such as enhanced blue-sky functionality and the reliability of Con Edison's system. The resilience management framework facilitates long-term adaptation and creates positive resilience feedback so that Con Edison's system achieves better functionality through time. To succeed, each component of a resilient system requires proactive planning and investments.

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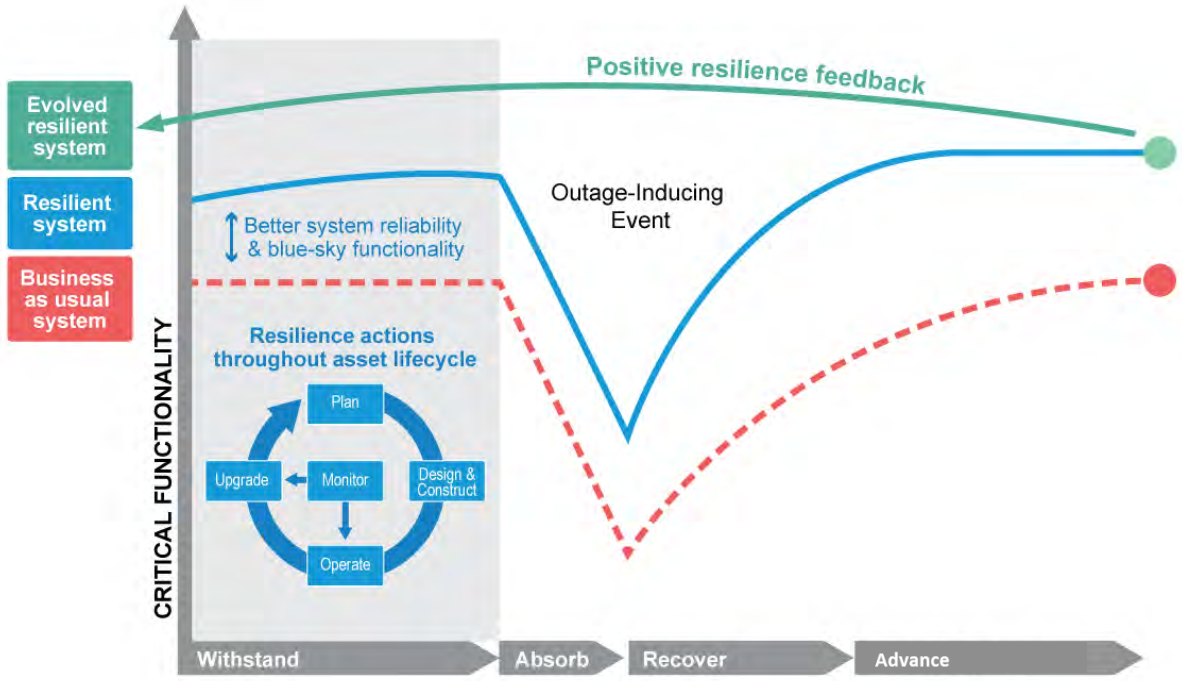
Figure 12 ■ Conceptual figure representing a resilience management framework designed to withstand changes in climate, absorb and recover from outage-inducing events, and advance to a better state. Investing in a more resilient system (blue line) provides benefits relative to a less resilient, or business-as-usual, system (red dashed line) before, during, and after an outage-inducing event. Most resilience actions should occur systematically throughout the asset life cycle to enhance the ability to withstand changes in climate, while also enhancing system reliability and blue-sky functionality. Resilient systems also adapt so that the functionality of the system improves through time (green line). Each component of a resilient system requires proactive planning and investments.



"Withstand" entails proactively strengthening the system to mitigate and avoid climate change risks and increase the reliability of Con Edison's system. "Withstand" investments are not necessarily a one-time event. Rather, the ability to withstand climate change must be integrated and revisited throughout the life cycle of Con Edison's assets. Doing so requires changes in the planning, design, and construction of new infrastructure; ongoing data collection and monitoring; and eventually investing in the upgrade of existing infrastructure, using forward-looking climate information. This life cycle approach to considering climate change is captured in Figure 13. Across Con Edison's electric, gas, and steam systems, planning for new investments in system capacity serves as a critical and strategic opportunity to integrate climate considerations. In addition, an important aspect of increasing the capacity of new investments to withstand changes in climate is maintaining strong design standards that account for gradual changes in chronic stressors and more frequent extreme events. However, since design standards do not apply to existing infrastructure, a strong monitoring program and signposts for additional adaptation investments could help ensure that Con Edison's existing infrastructure remains resilient to climate change by informing adjustments to operations and potential needs for upgrades.

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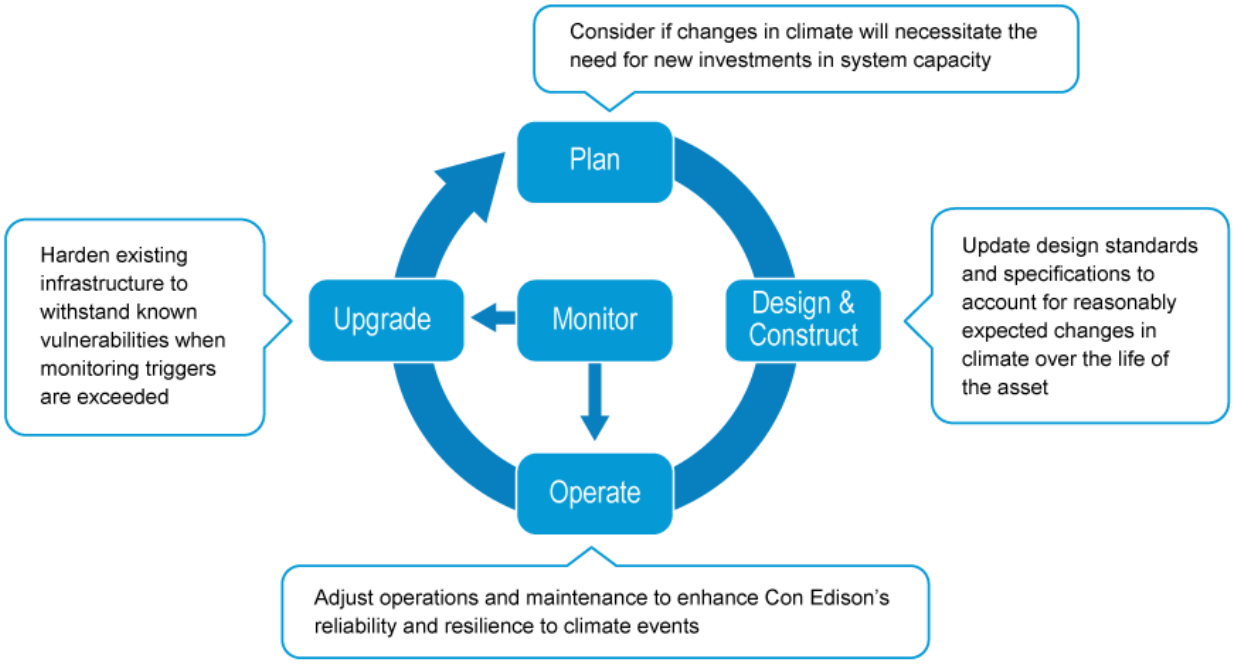
Figure 13 ■ "Withstand" actions and investments must be revisited throughout the life cycle of Con Edison's assets.



"Absorb" includes strategies to reduce the consequences of outage-inducing events, since Con Edison cannot and should not harden its energy systems to try to withstand every possible future low-probability, high-impact extreme weather event. These actions, many of which Con Edison is already implementing, include operational changes to reduce damage during outage-inducing events and to protect exposed systems from further damage.

"Recover" aims to increase the rate of recovery and increase customers' ability to cope with impacts after an outage-inducing event. Such strategies build on Con Edison's Emergency Response Plans and Coastal Storm Plans. In addition, there is a role that Con Edison can play to increase customer coping and prioritize the continued functioning of critical services. Resilient customers are those who are prepared for outages and are better able to cope with reduced energy service—through measures such as having on-site energy storage, access to locations in their community with power, the ability to shelter in place without power, and/or prioritized service restoration for vulnerable customers.

"Advance" refers to building back stronger after climate-related outages and updating standards and procedures based on lessons learned. Even with proactive resilience investments, outage-inducing climate events can reveal system or asset vulnerabilities. Adjusting Con Edison's planning, infrastructure, and operations to new and future risks after an outage-inducing event, while incorporating learning, will allow for a more effective and efficient transition to greater resiliency. Con Edison has taken this approach in the past, including investing a billion dollars in storm hardening measures after Superstorm Sandy. Moving forward, restoring service following an outage-inducing climate event to a better adapted, more resilient state begins with effective pre-planning for post-event reconstruction. Where assets need to be replaced during recovery, having a plan already in place for selection and procurement of assets designed to be more resilient in the future can help to ensure that Con Edison is adapting to future extremes in a continuously changing risk environment.

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Implementation of adaptation strategies throughout all of these phases will need to be adjusted over time to manage for acceptable levels of risk despite uncertainties about future conditions. The flexible adaptation pathways approach, described in further detail in the subsequent section, ensures the adaptability of adaptation strategies over time as more information about climate change and external conditions becomes available.

All Commodities (Electricity, Gas, and Steam)

Vulnerabilities

The Study team identified priority hazards for each of Con Edison's commodity systems (electric, gas, and steam) and found that several hazards were priorities across all three systems, although these hazards present unique vulnerabilities to the various assets within each system. The hazards common to all three systems are heat index, precipitation, sea level rise and storm surge, and extreme and multi-hazard events. These are discussed below. System-specific vulnerabilities are subsequently discussed in separate sections.

Heat Index

Worker safety may be a point of vulnerability if heat index values rise as projected. The Occupational Safety and Health Administration has set a threshold of 103°F for high heat index risk for people working under hot conditions. During the base period (1998–2017), there were 2 days per year with maximum heat greater than or equal to 103°F (but below 115°F). Under a lower emissions climate scenario (RCP 4.5 10th percentile), the 103°F threshold may be met 5 to 7 days per year by 2050; under a higher emissions scenario (RCP 8.5 90th percentile), this may occur 14 to 20 days per year by 2050. This poses a potential health threat to all Con Edison workers whose duties require outdoor labor.

Projected increases in heat index may also affect cooling equipment across Con Edison's systems, including the HVAC units for Con Edison buildings, air cooling towers for the electric system, and a water cooling tower for Con Edison's East River Steam Generating Plant. In order to supply sufficient cooling to its systems in 2080, Con Edison's HVAC systems will have to increase their capacity by 11% due to projected increases in dry bulb temperature. These systems have a roughly 15-year life span and therefore can be upgraded during routine replacements at an incremental cost of $1.3 million for 157 units. Similarly, Con Edison's cooling towers will have to increase their capacity by 30% by 2050. Cooling towers have a 20- to 35-year life span, allowing them to be upgraded during routine replacements at an incremental cost of $1.1 million for 19 cooling towers at 13 sites.

Precipitation

The Study team conducted an analysis of the physical and operational vulnerabilities of Con Edison's steam system, gas system, and transmission and substation components of the electric system. Findings indicated that all underground assets are vulnerable to flooding damage (i.e., water pooling, intrusion, or inundation) from heavy precipitation occurring over a short period of time. Specific vulnerabilities and their relevant thresholds vary significantly by commodity and, as such, are outlined in their respective sections.

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Sea Level Rise and Storm Surge

The Study team broke down evaluation of priority vulnerabilities related to sea level rise into two components.

The first component focuses on design standards for new infrastructure. The Study team assessed Con Edison's coastal flood protection standards for robustness to projected sea level rise. Con Edison's current design standard for coastal flood protections includes the FEMA 1% annual flood hazard elevation, 1 foot for sea level rise, and 2 feet of freeboard, which aligns with New York City's Climate Resilience Design Guidelines for critical infrastructure and water elevations that Con Edison experienced during Superstorm Sandy. Under high-end sea level rise (e.g., due to either rapid ice loss from the West Antarctic Ice Sheet corresponding to Kopp et al., 2017, or RCP 8.5 95th percentile projections corresponding to Kopp et al., 2014), the existing 1 foot sea level rise risk tolerance threshold could be exceeded by 2030; however, under more likely scenarios, the current threshold could be exceeded between 2040 and 2080.[12] The probability that sea level rise will exceed the 1-foot sea level rise risk tolerance by 2020 is under 10%; that increases to 65% to 70% by 2050, and to 100% by the 2080s.

The second evaluation component identified specific physical vulnerabilities of Con Edison's existing assets to impacts related to sea level rise, which are described by commodity below.

Extreme and Multi-Hazard Events

Assets across all systems are vulnerable to possible damage from extreme event flooding. Storm surge driven by an extreme hurricane event (i.e., a Category 4 hurricane) has the potential to flood both aboveground and belowground assets. Specific asset damage varies by commodity and is outlined in the commodity-specific sections. In addition, flooding from ice-melt and snowmelt may cause significant damage to assets across all commodities, especially if the melt contains corrosive road salts.

On an operational level, increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts. Con Edison's extreme weather response protocols are specified in the company's hazard-specific Emergency Response Plans and Coastal Storm Plans for electric, steam, and gas systems. Con Edison's current "full-scale" response, which calls for all Con Edison resources and extensive mutual assistance, is initiated when the number of customers out of service reaches approximately 100,000. However, low-probability extreme events can increase customer outages and outage durations by an order of magnitude, outpacing current levels of emergency planning and preparedness, as shown in Figure 14.

[12] The sea level rise projections use a baseline year of 2000. For more details on these projections and how they relate to Con Edison's design standards, see Appendix 4.

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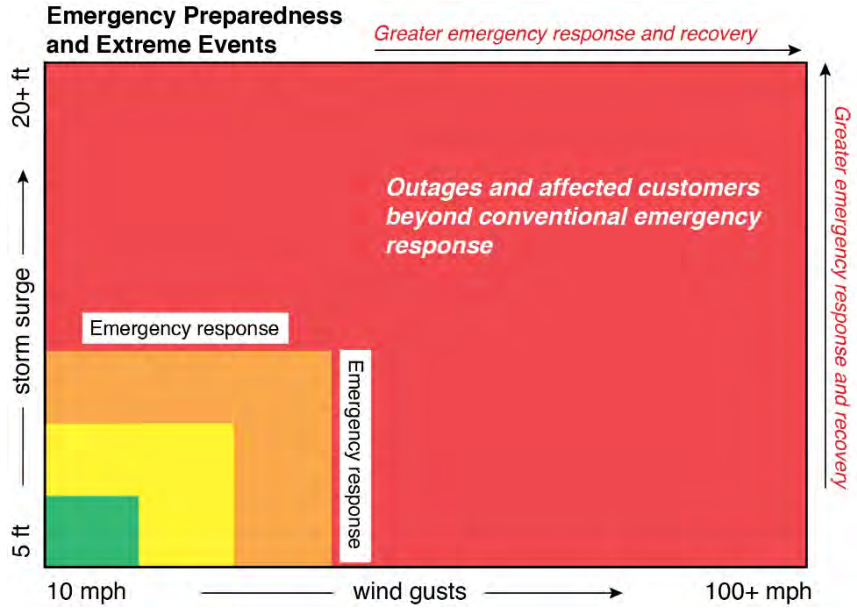
Figure 14 ■ Schematic diagram illustrating the increasing impacts during an extreme event (e.g., hurricane with extreme wind gusts and storm surge) that demands correspondingly large emergency response efforts that may exceed those experienced historically.



Adaptation Measures to Address Vulnerabilities

Several adaptation measures help address vulnerabilities across Con Edison's electric, gas, and steam systems: improved monitoring systems and capabilities to support planning and decision making, emergency preparedness and full system recovery, and improved customer coping.

Improved Monitoring Systems and Capabilities to Support Planning and Decision Making

Con Edison can collect updated and comprehensive data to further strengthen the resilience of its long-term plans and decision-making processes to climate change. Signposts guide planning and decision making, especially through informing the timing of implementation and the adjustment of adaptation measures, described in greater detail in the section below on Moving Towards Implementation.

As previously mentioned, it is important to have the latest information on climate variables and projections as the climate changes and the science improves. Monitoring local climate rates of change across the service territory can help Con Edison better track both changing conditions and potential points of vulnerability across its systems. Specific adaptation measures per commodity that are dependent on the monitoring of climate variable information are detailed in the respective commodity sections. In addition to information on climate variables, Con Edison will need to stay abreast of the latest climate science projections generated by expert organizations such as IPCC, NCA, and NPCC. The Study team suggests that Con Edison could revise its planning and decision-making processes at least every 5 years to incorporate updated climate science information.

Emergency Preparedness and Full System Recovery

Con Edison should consider a range of adaptation strategies to increase capacity for an efficient preparedness and recovery process, as defined in Table 3.

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Table 3 ■ Emergency preparedness and system recovery adaptation strategies

Adaptation Strategy	Measures
Strengthen staff skills for streamlined emergency response.	• Use technology to increase the efficiency of emergency response work crews. • Review the Learning Center courses to ensure that crews are developing the skills required for emergency response. • Incorporate supply shortages into emergency planning exercises.
Plan for resilient and efficient supply chains.	• Develop a resilience checklist for resilient sourcing. • Have a plan already in place for selection and procurement of assets designed to be more resilient in the future. • Ensure that parts inventories are housed out of harm's way and in structures that can survive extreme weather events. • Standardize equipment parts, where possible.
Coordinate extreme event preparedness plans with external stakeholders.	• Continue coordination with telecommunication providers, including through joint emergency response drills. • Continue and strengthen collaboration with the city to improve citywide design, maintenance, and hardening of the stormwater system. For example, improved drainage could alleviate the potential impacts of flooding and increase the effectiveness of adaptation measures in which Con Edison invests (e.g., drain hardening at manholes).
Incorporate low probability events into long-term plans.	• Continue expanding the Enterprise Risk Management framework to include lower probability extreme weather events and long-term issues (e.g., 20+ years). • Conduct additional extreme weather tabletop exercises informed by the future narratives outlined in this report, and consecutive extreme weather events. • Consider expanding the definition of critical facilities and sensitive customers.
Track weather-related expenditures.	• Con Edison's Work Expenditures Group could track expenditures, such as the cost of outages and repairs or customer service calls. Concurrently tracking climate and cost data will enable Con Edison to perform correlation analysis over time.
Update extreme event planning tools.	• Con Edison currently uses an internal Storm Surge Calculator (an Excel workbook that determines the flood measures to be employed for coastal assets based on a given storm tide level) to help plan for coastal flooding impacts. Con Edison could adjust inputs to this program to reflect the following: – Updated storm surge projection information, using high-end forecasted surge – Information from coastal monitoring, such as sea level rise and coastal flooding • In addition, Con Edison could regularly revisit the definition of critical equipment so that the Storm Surge Calculator can best inform prioritization of equipment upgrades.
Expand extreme heat worker safety protocols.	• Implement safety protocols (e.g., shift modifications and hydration breaks) practiced in mutual aid work in hotter locations such as Florida and Puerto Rico. • Examine and report on the levels of workers necessary to prepare for and recover from extreme climate events.
Improve recovery times through system and technology upgrades.	• Consider the use of drones and other technology (satellite subscription) or social media apps for damage assessment. • Use GIS system to facilitate locating and documenting damage. • Expand the use of breakaway hardware and detachable service cable and equipment.

Improved Customer Coping

Extreme events can present outsized risks compared to chronic events—risks that, in some cases, also extend to larger geographic areas. For example, impacts from hurricanes can overwhelm multiple facets of Con Edison's system and surrounding communities. Con Edison is positioned at the center of increasingly interconnected societal, technological, and financial systems, making it difficult and inefficient to evaluate risks solely on a component-by-component basis (Linkov, Anklam, Collier, DiMase, & Renn, 2014). Together,

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these factors necessitate different approaches to considering adaptation compared with climate changes for which probabilities are more easily assigned.

While the City of New York has primary responsibility for coordinating resident emergency response efforts, Con Edison can play a role in increased customer coping and resilience. This includes helping customers cope with reduced energy service if an extreme event leads to prolonged outages (e.g., supporting on-site energy storage, access to locations in the community with power, prioritized service restoration for vulnerable areas). Table 4 provides more specific adaptation strategies. Overall, Con Edison could consider expanding the definition of critical facilities and sensitive customers.

Table 4 ■ Improved customer coping adaptation strategies

Adaptation Strategy	Measures
Create resilience hubs (see below for more information).	• Use solutions such as distributed generation, hardened and dedicated distribution infrastructure, and energy storage so that resilience hubs can function akin to microgrids to provide a range of basic support services for citizens during extreme events. • Continue to promote the pilot resilience hub at the Marcus Garvey Apartments in Brooklyn, using a lithium ion battery system, fuel cell, and rooftop solar to provide back-up power to a building with a community room that has refrigerators and phone charging. • Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs. • Use AMI capabilities to preserve service for vulnerable populations, if possible.
Invest in energy storage.	• Continue to enhance customer resilience through continued installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations. • Continue to explore ways to help customers install, maintain, and make use of distributed energy resource assets for power back-up, self-sufficiency, and resilience purposes.
On-site generation	• Con Edison currently supports on-site generation for customers through programs such as rebate and performance incentives for on-site residential and commercial photovoltaic solar generation, incentives for behind-the-meter wind turbines, and incentives for combined heat and power projects that Con Edison currently facilitates in collaboration with the New York State Energy Research and Development Authority. • On-site generation is a recommended approach for locations where resilience hubs may not be affordable or necessary. • Con Edison could continue to encourage on-site generation for individual businesses and residential buildings.
Energy efficiency	• Support improved passive survivability, or the ability to shelter in place for longer periods of time, through enhanced energy efficiency programs. • Continue to support energy efficiency programs and further expand its energy efficiency program portfolio to include additional incentives for energy-efficient building envelope upgrades.

Resilience hubs are an emerging idea in resilience planning, which focus on building community resilience by creating a space (or spaces) to support residents and coordinate resources before, during, and after extreme weather events (Baja, 2018). A key requirement for a resilience hub is continued access to energy services. The objective of a resilience hub is to be able to provide a range of basic support services for citizens during extreme events. To accomplish this, resilience hubs may require a hybrid energy solution that includes multiple generation sources (e.g., solar and natural gas generation) and energy storage (i.e., batteries), plus dispatching controls, similar to the functionality of a microgrid. Figure 15 and Figure 16 demonstrate how a fuel cell-based microgrid can be used to power key community locations during normal operating conditions and during emergency events.

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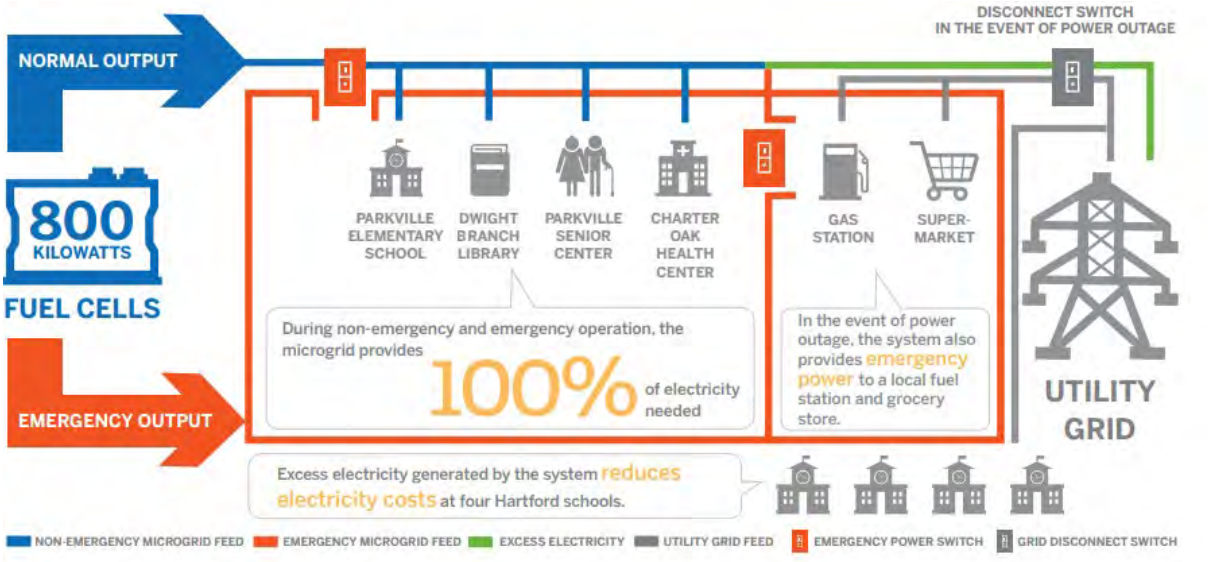
Figure 15 ■ Fuel cell-based microgrid supplying energy to key community locations (Constellation Energy)

Figure 16 ■ Diagram of microgrid operations during normal and emergency operations (Constellation Energy)



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Electric System

Electric System Overview

Con Edison's electric service territory includes both New York City and Westchester County, covering an area of 660 square miles and serving 3.3 million customers. Figure 17 depicts a schematic of the Con Edison electric system.

Con Edison's grid is a delivery system that connects energy sources to customers. While most electricity delivered is produced by large third-party generating stations, distributed energy resources also supply energy to the grid.

Energy produced by generating sources is delivered via the Con Edison transmission system, which includes 430 circuit-miles of overhead transmission lines and the largest underground transmission system in the United States, with 749 circuit-miles of underground cable. The system also includes 39 transmission substations. The high-voltage transmission lines bring power from generating facilities to transmission substations, which supply area substations, where the voltage is stepped down to distribution levels.

Con Edison has two different electric distribution systems—the non-network (primarily overhead) system and the network (primarily underground) system. The network system is segmented into independent geographical and electrical grids supplied by primary feeders at 13 kilovolts (kV) or 27 kV. The non-network system is designed using either overhead autoloops with redundant sources of supply, or 4-kV overhead grids arranged in a network configuration or as underground residential distribution systems designed in loop configurations.

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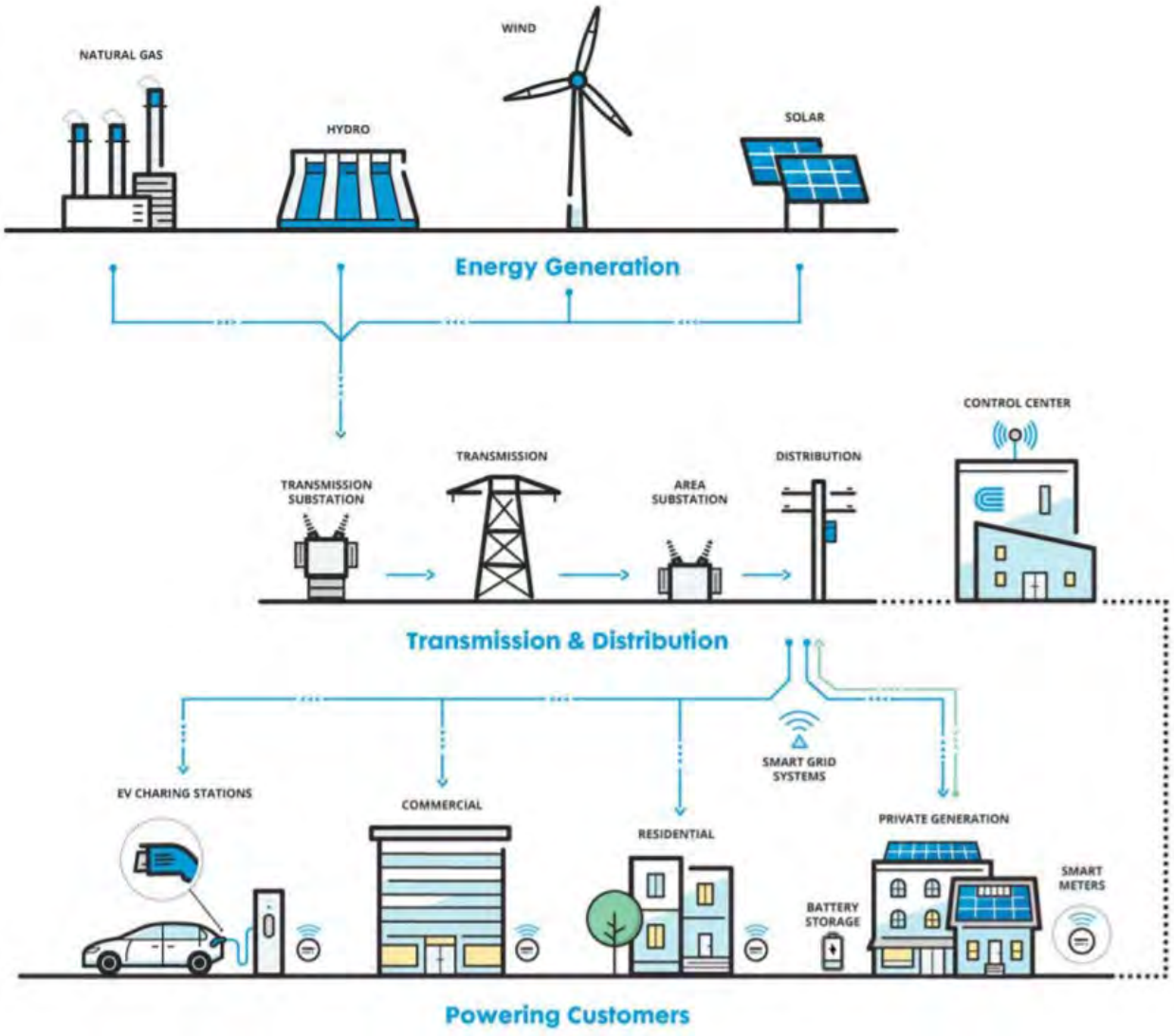
Figure 17 ■ Diagram of the Con Edison Electric System



Electric Vulnerabilities

Assets in the electric segment of Con Edison's business are most vulnerable to climate-induced changes in temperature/humidity and sea level rise. Both climate hazards have already shown their ability to bring about outages or damage assets and interrupt operations and carry the potential for future impacts. More information on specific vulnerabilities for these and other climate stressors is discussed below.

Heat and Temperature Variable (TV)

The core electric vulnerabilities for increasing temperature and TV include increased asset deterioration, decreased asset capacity, decreased system reliability, and increased load. Figure 18 illustrates how temperature-related stressors, such as maximum and average air temperature, lead to impacts on the electric system.

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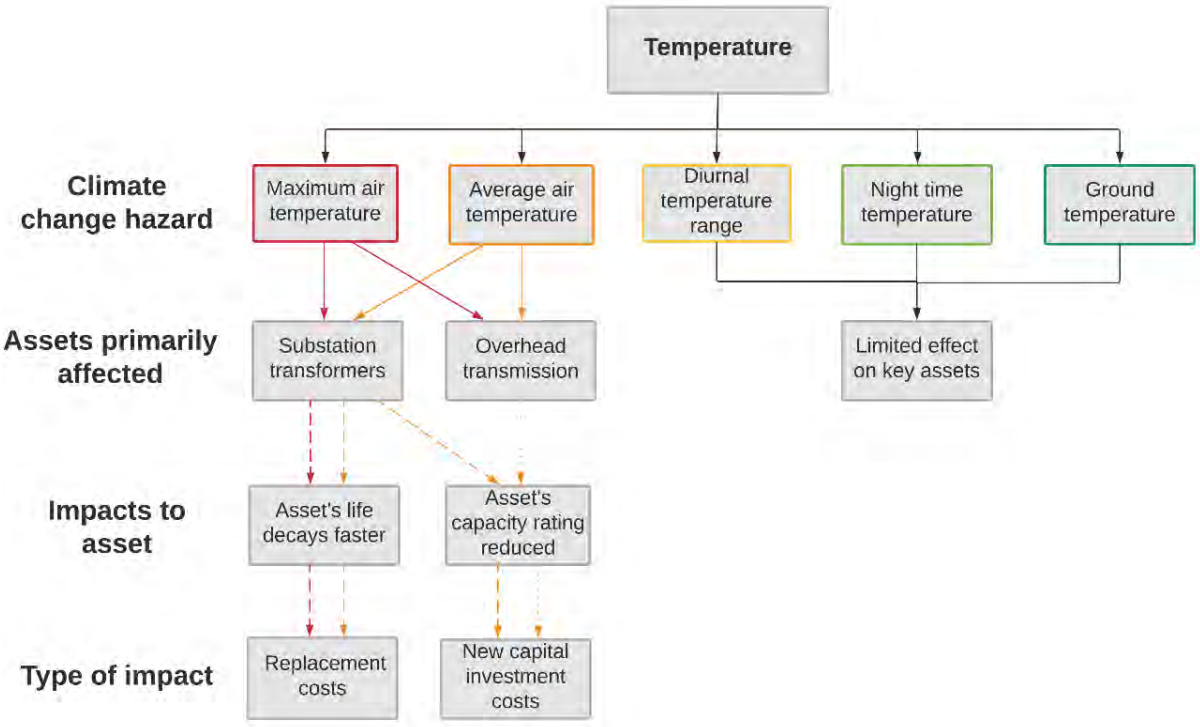
Figure 18 ■ Temperature-related impacts on Con Edison's electric system



Increased Asset Deterioration

Increased average temperatures pose a threat to substation transformers. Within a substation, transformers are the asset most likely to be affected by projected higher temperatures since their ambient temperature design reference temperature is lower (i.e., 86°F) than that of most other assets.[13] Higher average and maximum ambient temperatures increase the aging rate of the insulation in transformers, resulting in decreased asset life.[14]

Decreased Asset Capacity

Because an asset's internal temperature is the result of the ambient temperature in which it operates, as well as the amount of power it delivers, operating in an ambient temperature above the design reference temperature decreases the operational rating of the asset. However, derating the system due to increasing temperatures would effectively decrease the capacity of the system. When the capacity of the system is decreased, Con Edison must make investments to replace that capacity. The Con Edison system is currently designed with the capacity to meet a peak summer demand of more than 13,300 megawatts (MW). Based on projected temperature increases, capacity reductions in 2050 could range from 285 MW

[13] Buses, disconnect switches, circuit breakers, and cables all have a design reference temperature of 104°F or higher.
[14] Not every excursion above the designed-for temperature will result in decreased service life. Two conditions must be met for the useful life of the transformer insulation to experience an increased rate of decay: (1) the ambient reference temperature rating must be exceeded, and (2) the transformer must be operating at the rated load, typically as a result of the network experiencing a single or double contingency.

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to 693 MW for overhead transmission, switching stations, area station and sub-transmission, and network transformers.[15] This could potentially result in a capital cost of $237 million to $510 million by 2050.

The primary impact of increases in ambient temperatures on overhead transmission lines (assuming peak load) is increased line sag. Insufficient line clearance presents a safety risk should standard measures such as vegetation management not alleviate the risk. If standard measures cannot be applied, the lines would have to be derated and investments would be needed to replace the diminished capabilities of the line.

Decreased System Reliability

Increases in TV-related events are expected to affect the electric network and non-network systems by decreasing reliability. Con Edison uses a Network Reliability Index (NRI) model to determine the reliability of the underground distribution networks.[16] Con Edison has set an NRI value of 1 per unit (p.u.) as the threshold over which reliability is considered unacceptable. Currently, there are no networks that exceed this standard.

The Study team modeled how the NRI value of each network would change without continued investments in the system. The forward-looking NRI analysis found that with an increase in the frequency and duration of heat waves by mid-century, between 11 and 28 of the networks may not be able to maintain Con Edison's 1 p.u. standard of reliability by 2050, absent adaptation. Under the higher emissions scenario (RCP 8.5 90th percentile), projected impacts are relatively severe, even by 2030, with up to 21 total networks projected to exceed the NRI threshold by that year, absent adaptation (Figure 19). These deficiencies can be reduced by continuing to make investments to better withstand climate events, which Con Edison has done in the past through measures such as infrastructure hardening and added redundancy, diversity, and flexibility in power delivery. Such measures carry the co-benefit of improving blue-sky functionality and reliability.

Currently, Con Edison replaces paper-insulated, lead-covered (PILC) cables as an effective first line of defense against NRI increases. Con Edison is committed to continued investment in this measure, which will help reduce this heat-related vulnerability in the near term. The Study team also quantified the value of other measures to maintain network reliability, including innovative distribution designs and the use of distributed resources, which can be part of microgrids.

[15] The assumed decrease in capacity is 0.7% per °C (0.38% per °F) for substation power transformers, and 1.5% per °C (0.8% per °F) for overhead transmission conductors (Sathaye, 2013).

[16] NRI is a Monte Carlo simulation used to predict the performance of a network during a heat wave. The program uses the historical failure rates of the various components/equipment that are in the network, and through probability analysis determines which networks are more likely to experience a shutdown.

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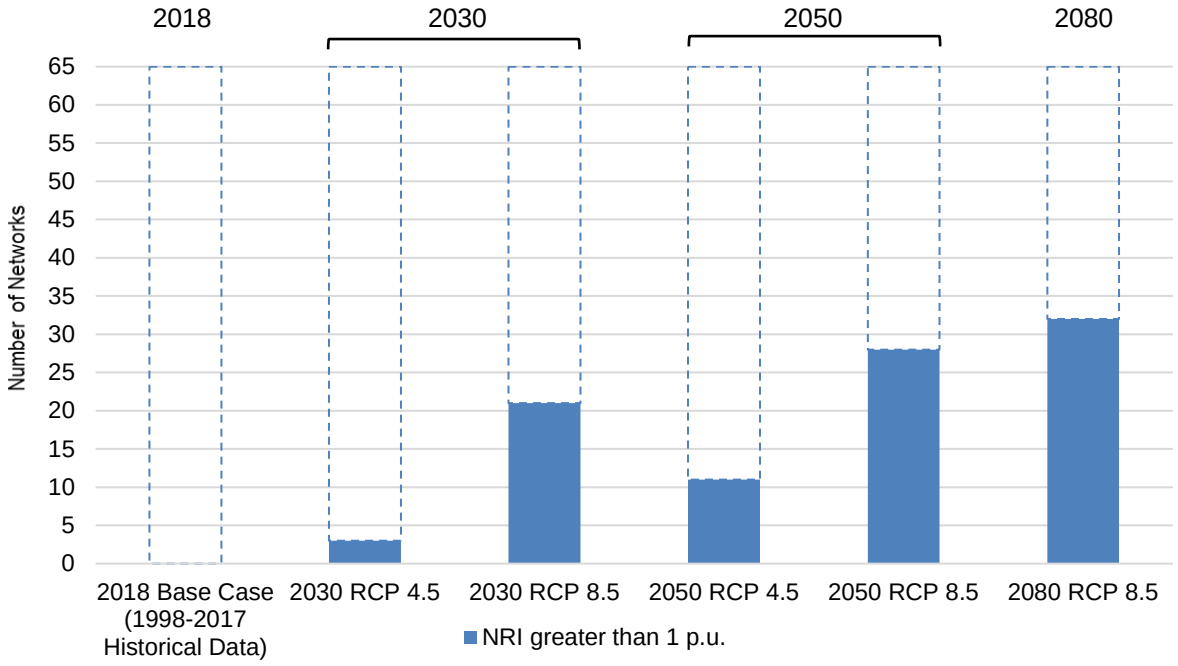
Figure 19 ■ The number of networks above the NRI threshold of 1 p.u. under both climate scenarios for 2030, 2050, and 2080



The Study team also analyzed the impact of climate change on non-network reliability, which is measured in terms of the System Average Interruption Frequency Index (SAIFI).[17] The results indicate that the reliability of the non-network system is somewhat vulnerable to heat events; however, climate impacts would be negligible out to 2080. The average contribution to reliability from non-network autoloop feeder failures and 4-kV grid supply feeder failures due to increased temperatures would only contribute up to 8% of the maximum threshold SAIFI of 0.45 (i.e., a 0.035 increase in SAIFI in 2080) (New York Department of Public Service, 2018).

Increased System Load

When temperature and humidity increase, demand for electricity for cooling also increases. Therefore, higher TV in the summer can cause higher peak loads. The Study team found an increase in peak load in 2050 of 6.9% to 19.2%, as compared to historical conditions. These projected changes in load are due only to the impact of changing TV, and do not take into consideration changes in other factors (e.g., population, increased air conditioning penetration). The Study team found a decrease in winter peak electric load.

Increases in load may require investments in system capacity to meet the higher demand. This cost could be between $1.1 billion and $3.1 billion by 2050. The 10- and 20-year load relief investment plans use asset ratings and load forecasts as key inputs, both of which include temperature as a factor. This combination of a greater demand and a decreased capacity to fill that need will likely warrant a revision to the load relief planning process in the future (Table 5).

[17] SAIFI is a measure of customer reliability. It is the average number of times that a customer is interrupted for 5 minutes or more over the course of 1 year.

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Table 5 ■ The combined impacts of increased load and asset capacity reduction in 2050

Scenario	Total capacity under base and future temperature conditions (MW)	Incremental capacity reduction due to temperature	Peak load during current and future 1-in-3 events (MW)	Incremental load increase due to changes in TV	Total additional capacity needed under climate scenarios (MW)
Base Case 2050	13,300	0	13,525	–	0
RCP 4.5 10th percentile 2050	13,015	285	14,949	1,424	1,709
RCP 8.5 90th percentile 2050	12,607	693	16,491	2,966	3,659

Secondary Vulnerabilities

The Study team identified additional heat and humidity-related vulnerabilities in Con Edison's system that were not flagged as priority vulnerabilities but nonetheless present risks.

- **Transmission system:** Con Edison's current transmission system is designed for the highest anticipated loads based on historical values. The Study team found that while load exceeded 90% of the peak load (presenting the possibility for thermal overload) on 1.5% of summer days historically, by 2050, this may increase to 5.2% of days under the RCP 8.5 90th percentile scenario. This shift in TV distribution may result in a small increase in the frequency of load drop from the transmission system.
- **Summer operations and voltage reductions:** When summer temperatures soar, Con Edison implements a set of procedures to avoid voltage and thermal stresses on the system. These procedures are triggered by a threshold (e.g., TV 86, which is the 1-in-3 peak load-producing TV). The Study team found that there could be a significant increase in the number of days with voltage reductions and summer work restrictions. However, if Con Edison continues to invest in the system to ensure operational capacity during the 2050 1-in-3 TV event, then there will be a drop in the frequency of voltage reductions and summer work restrictions, relative to today.
- **Corporate Emergency Response Plan:** Con Edison also uses TV thresholds to trigger elevated threat levels under its Corporate Emergency Response Plan (CERP). The Study team conducted an analysis to understand how the projected changes in TV will affect the exceedance of current CERP threat levels. The analysis indicates that TV conditions exceeding current thresholds will increase in both the lower (RCP 4.5 10th percentile) and higher (RCP 8.5 90th percentile) climate change scenario. The conditions for reaching a "Serious" threat level based on the current thresholds, for example, would increase from 0.4 days per summer, on average, to 1.8 days under RCP 4.5, and 12.8 days under RCP 8.5.
- **Volume forecasting:** Con Edison conducts volume forecasting to estimate the volume of energy the company needs to purchase, a portion of which is weather-sensitive. The calculation for this portion relies primarily on heating degree-days (HDDs) for the winter and cooling degree-days (CDDs) for the summer. The Study team estimated that Con Edison could experience an increase in summertime CDDs, which could result in the energy delivery increasing from 43,077 gigawatt-hours (GWh) in 2050 under the base case to 43,685 GWh under the RCP 4.5 scenario (a 1.4% increase), and to 45,394 GWh under the RCP 8.5 scenario (a 5.4% increase). The Study team found a less significant decrease in HDDs due to climate change.

Sea Level Rise

RCP 4.5 and RCP 8.5 projections indicate that sea level rise may exceed Con Edison's current design standard for coastal flood protection (i.e., a 100-year storm with 1 foot of sea level rise and 2 feet of

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freeboard) between 2030 and 2080. The Study team analyzed the exposure of Con Edison's assets to 3 feet of sea level rise (i.e., the 2080 RCP 8.5 83rd percentile sea level rise projection), keeping the other elements of Con Edison's existing risk tolerance constant (i.e., a 100-year storm with 2 feet of freeboard). By summing the freeboard and sea level rise values, this equates to FEMA's 100-year floodplain elevation plus 5 additional feet.

Of the 324 electric substations (encompassing generating stations, area substations, transmission stations, unit substations, and Public Utility Regulating Stations [PURS]), 75 would be vulnerable to flooding during a 100-year storm if sea level rose 3 feet. Three of these potentially exposed substations would only require minimal modifications to protect them, 16 would require an extension of existing protections, eight would require a new protection approach (i.e., the existing protections cannot be extended), and 48 do not have existing protections because they are outside of the floodplain. Hardening all these substations is estimated to cost $636 million.

Precipitation

The Study team found that substations, overhead distribution, underground distribution, and the transmission system are most at risk for precipitation-based hazards.

Substations may experience an overflow of water from transformer spill moats, which could release oil-contaminated water within the substation. However, the risk of such an event is low, as transformer spill moats are built at a level that is robust to all but a severe and highly improbably conjunction of events.[18]

The transmission and overhead distribution systems are both vulnerable to the accumulation of radial ice, which can build up on lines and towers during winter precipitation events. In extreme scenarios, accumulation of radial ice can result in unbalanced structural loading and subsequent transmission line failure, especially when accompanied by heavy winds (Nasim Rezaei, Chouinard, Legeron, & Langlois, 2015). Con Edison's current system meets the National Electrical Safety Code standard for radial ice and is robust to ice accumulation. It is uncertain whether climate change will increase or decrease the intensity of future icing events.

The underground distribution system is vulnerable to flooding and salt runoff from snowfall and ice events. Flooding can damage non-submersible electrical equipment. This risk is mitigated through Con Edison's designs: All underground cables and splices operate while submerged in water, and all underground distribution equipment installed in current flood zones (and all new installations) are submersible. Snowfall and ice require municipalities to spread salt on roads, which eventually seeps into the ground with runoff water. Road salt can degrade wire insulation and lead to insulation burning and arcing, potentially causing safety concerns and customer outages. It is currently unclear how salting frequency will change over time.

Extreme Events

Hurricanes and nor'easters present physical risks associated with heavy winds, precipitation, and flooding, which can lead to widespread system outages and, at worst, physical destruction. During hurricanes, wind stress and windblown debris can lead to tower and/or line failure of the overhead transmission system

[18] In accordance with New York State code and federal Spill Prevention, Control, and Countermeasure recommendations, Con Edison's transformers are protected by moats designed to hold water from a 6-inch, 1-day storm event, in addition to the gallons of oil that may be released during a spill event and a further 50,000–60,000 gallons of fire suppression fluid. Based on this standard, Con Edison's substation transformer moats are robust to 6 inches of rain during a catastrophic emergency, and significantly more than that at all other times.

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and damage overhead distribution infrastructure, which could cause widespread customer outages. Intense rain during hurricanes can also flood substations, which may cause an overflow of oil-contaminated water from transformer spill moats. A Category 4 hurricane could very likely lead to outages for more than 600,000 non-network customers and more than 1.6 million network customers.

During nor'easters, accumulation of radial ice can cause tower or line failure of the overhead transmission system. Similarly, snow, ice, and wind can damage the overhead distribution system. Indirectly, salt put down by the city to contend with snow and ice accumulation on roads could infiltrate the underground distribution system, causing arcing and failure of underground components.

Extreme heat waves present a range of effects that can contribute to failures, including a lower ampacity rating while increasing load demand, causing cables and splices to overheat, transformers to overheat, and transmission and distribution line sag. Distribution network component failures can cause Con Edison to exceed the network reliability design standard. Greater line sag can lead to flashovers and line trips.

Adaptation Options for the Electric System

Withstand

In the short term, Con Edison can work to address the vulnerabilities of the electric system by integrating climate hazard considerations into planning, collecting data on priority hazards, and updating design strategies.

There are several opportunities to integrate climate change data into planning processes. For example, Con Edison could integrate climate change projections into long-term load forecasts, consult utilities in cities with higher temperatures to refine the load forecast equation for high TV numbers, and develop a load relief plan that integrates future changes in temperature and TV into asset capacity and load projections. During load relief planning, Con Edison could also consider whether extreme events may shift the preferred load relief option—frequent extreme heat could reduce the effectiveness of demand response programs. For the transmission system, Con Edison could integrate considerations of climate change into the long-range transmission plan. For the distribution system, Con Edison could integrate climate projections into NRI modeling and install high-reliability components,[19] as needed.

Given the potential risks that temperature and heat waves pose to the electric system, the Study team suggests that Con Edison could collect data on these hazards to build greater awareness of their impacts to the system, as well as to monitor for signposts that would trigger additional action. Specifically, Con Edison could:

[19] System components vary in their reliability. For example, PILC cable performs more poorly than solid dielectric cable.

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- Install equipment capable of collecting, tracking, and organizing temperature data at substations to allow for location-specific ratings and operations.
- Make ground temperature data more accessible and track increases over time.
- Expand monitoring and targeting of high-risk vegetation areas.
- Continue to track line sag and areas of vegetation change via light detection and ranging (LiDAR) flyovers to identify new segments that may require adaptation.

These data could be used to routinely review asset ratings in light of observed temperatures. Con Edison could also incorporate heat wave projections into reliability planning for the network system.

Hurricanes are another priority hazard for the electric system and therefore warrant robust planning tools that capture potential changes in climate. Con Edison could complement their existing model used to predict work crews required to service weather-driven outages with an updated model that better resolves extreme weather events and extreme weather impacts on customers in the service territory.

Design standards are a way to help standardize resilience by ensuring that new assets are built to withstand the impacts of climate change hazards. The Study team suggests a variety of design standards:

- **Temperature:** Standardize ambient reference temperatures across all assets for development ratings.
- **Precipitation:** Update precipitation design standards to reference National Oceanic and Atmospheric Administration (NOAA) Atlas 14 for up-to-date precipitation data. Consider updating the design storm from the 25-year precipitation event to the 50-year event to account for future increases in heavy rain events.
- **Sea Level Rise:** Revise design guidelines to consider sea level rise projections and facility useful life. Continue to build to the higher of the FEMA + 3′ level and the Category 2 storm surge levels at new-build sites, as is current practice. Add sea level rise to the Category 2 maps to account for future changes and a greater flood height/frequency.

In addition to these systematic approaches, Con Edison can also help the electric system better withstand climate hazards through asset-specific physical adaptation measures, when needed. Table 6 illustrates these physical options.

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Table 6 ■ Potential physical adaptation options for electric assets

Main Hazard(s)	Vulnerable Assets or Plan	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Temperature	Grid modernization	Continue to invest in grid modernization to increase resilience to climate change through new technology and increased data acquisition. Efforts include distribution automation, grid-edge sensing (environmental, AMI), asset health monitoring, conservation voltage optimization, and targeted system upgrades.	Continuous	Change in ambient operating temperatures, including changes in science-based projections
Heat Waves	Network system, which may experience reduced reliability (and therefore increased NRI) due to heat waves	Complete PILC cable replacements.	2030	Increased frequency or duration of heatwaves
		Continue implementing load relief strategies to keep NRI ratings below 1. Options include: • Split the network into two smaller networks. • Create primary feeder loops within and between networks. • Install a distribution substation. • Incorporate distributed energy resources and non-wire solutions. • Design complex networks that consider combinations of adaptation measures.	Continuous	NRI value over 1 p.u.
	Non-network distribution system	Maintain non-network reliability in higher temperatures by implementing the following: • Autoloop sectionalizing • Increased feeder diversity	2080	Forecasted System Average Interruption Frequency Index (SAIFI) ratings (incorporating climate change projections) above established thresholds
	Overhead transmission	Replace limiting wire sections with higher rated wire to reduce overhead transmission line sag during extreme heat wave events. Alternatively, remove obstacles or raise towers to reduce line sag issues.	Continuous	Increased incidence of line sag; higher operating temperatures
		Explore incorporating higher temperature-rated conductors.	2050	Existing asset replacement
	Area and transmission substation transformers	Undertake measures that contribute to load relief, such as energy efficiency, demand response, adding capacitor banks, or upgrading limiting components, such as circuit breakers, or disconnect switches and buses.	2030/2050	Ambient temperatures exceeding asset specifications
		Gradually install transformer cooling, or replace existing limiting transformers within substations.	2050/2080	Ambient temperatures exceeding asset specifications
Precipitation	Substations	Harden electric substations from an increased incidence of heavy rain events by doing the following: • Raising the height of transformer moats • Installing additional oil-water separator capacity • Increasing “trash pumps” behind flood walls to pump water out of substations	2080	Changes in the 25-year return period storm
	Transmission and overhead distribution	Underground critical transmission and distribution lines.	2080	Increased incidence of icing

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Main Hazard(s)	Vulnerable Assets or Plan	Adaptation Option	Implementation Timeframe	Signpost or Threshold
	Underground distribution	Retrofit ventilated equipment with submersible equipment to eliminate the risk of damage from water intrusion.	2050	Expanded area of precipitation-based flooding; better maps of areas at risk for current and future precipitation-based flooding
		Reduce the incidence of manhole events due to increased precipitation and salting by doing the following: • Expanding Con Edison's underground secondary reliability program • Accelerated deployment of vented manhole covers • Replacement of underground cable with dual-layered and insulated cable, which is more resistant to damage • Installation of sensors in manholes to detect conditions indicating a potential manhole event	2050	Increase in the City's use of salt over the winter period; increased rate of winter precipitation
Hurricanes	Overhead transmission	Continue to expand existing programs to reinforce transmission structures; address problems with known components.	Continuous	Increased frequency/severity of heavy winds; existing asset replacement
	Overhead distribution	Invest in retrofits for open wire design with aerial cable and stronger poles.	2080	Increased frequency/severity of heavy winds; existing asset replacement
		Underground critical sections of the overhead distribution system to ensure resilience against hurricane force winds and storm surge.	2080	Increased frequency/severity of heavy winds
Nor'easters	Overhead transmission and distribution	Continue to expand programs to reinforce transmission and distribution structures and expand the number of compression fittings used to address weak points in transmission lines.	Continuous	Increased incidence of icing; existing asset replacement
	Underground distribution	Upgrade high failure rate components.	Continuous	Increased frequency/severity of nor'easter events

Of course, it is neither practical nor feasible for Con Edison to build resilience to the point that its electric system can fully withstand the impacts of all climate hazards. The Study team thus suggests that Con Edison consider the following strategies to help the electric system better absorb and recover from impacts:

Absorb

- **Temperature:** Increase capabilities to provide flexible, dynamic, and real-time line ratings.
- **TV:** Routinely update voltage reduction thresholds and hands-off thresholds to account for changes in climate and the changing design of the system.
- **Hurricanes:** Continue to explore and expand operational measures to increase the resiliency of the overhead distribution system by increasing spare pole inventories to replace critical lines that are compromised during extreme weather events.
- **Heat waves:** Stagger demand response consecutive event days across different customer groups to increase participation; ensure that demand response program participants understand the purpose/cause of the event; use technology to more efficiently regulate load/use AMI to rapidly shed

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load on a targeted network to help ensure that demand does not exceed supply; and continue installation of energy storage strategies, including on-site generation at substations or mobile storage on demand/transportable energy storage system (TESS) units, and compressed natural gas tank stations.

Recover

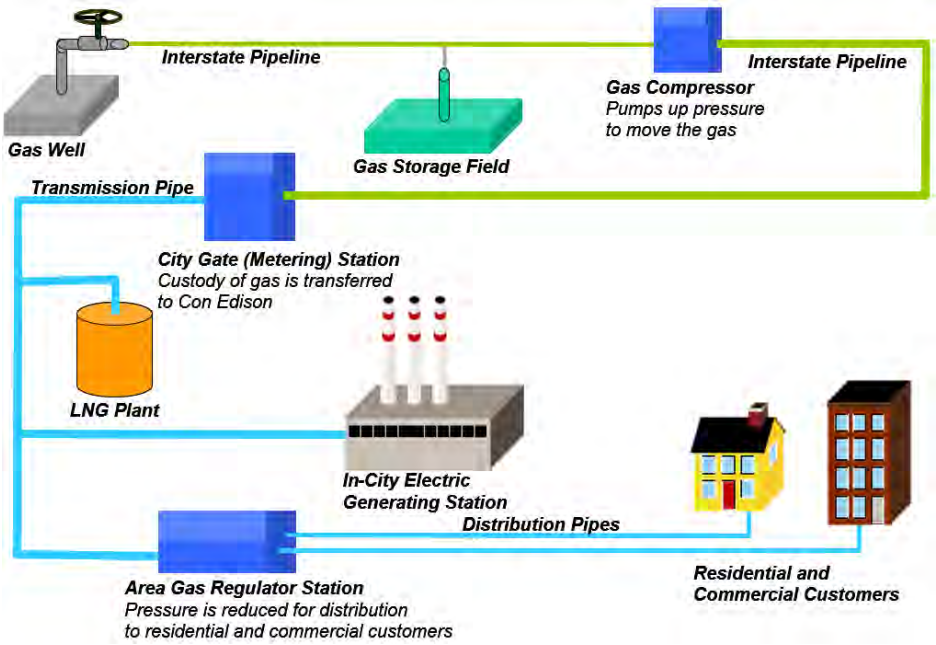
- **Heat waves:** Continue to actively engage forward-looking technologies to improve extreme recovery time for distribution systems, such as automated splicing systems to reduce feeder processing times.
- **Extreme events:** Support additional deployment of hybrid energy generation and storage systems at critical community locations and resilience hubs; support increasing the percentage of solar/other distributed generation projects to allow for islanding; encourage on-site generation for individual businesses and residential buildings; and increase the use of LiDAR and drones to assess damage and reduce manual labor.

Gas System

Gas System Overview

Con Edison's gas service territory covers Manhattan, Bronx, Westchester, and parts of Queens. Con Edison serves approximately 1.1 million firm customers and 900 large-volume interruptible customers who can alternate fuel sources. The natural gas system consists of more than 4,359 miles of pipe transporting approximately 300 million dekatherms (MMdt) of natural gas annually. About 56% of the system operates at low pressure, 11% operates at medium pressure, and 33% operates at high pressure. Figure 20 depicts the Con Edison natural gas delivery chain.

Figure 20 ■ Con Edison natural gas delivery chain



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Gas Vulnerabilities

Most of Con Edison's gas assets are underground, and gas load peaks in the winter rather than in the summer, which means that gas assets are less likely to be damaged by subaerial extreme events, such as heat waves, lightning, and strong winds. As discussed in Con Edison's Post Sandy Enhancement Plan, Con Edison's gas assets are most vulnerable to underground water intrusion caused by flooding, and thus projected increases in the frequency of heavy precipitation and downpours, sea level rise and storm surge, and hurricanes and nor'easters pose a significant risk (Con Edison, 2013).

Water intrusion can occur if underground water enters gas pipes or mains and may result in a drop in pressure and lead to scattered service interruptions; low-pressure segments of the system and cast iron pipes are particularly vulnerable to this risk. In addition, pipe sections near open-pit construction projects may also be more vulnerable, because open excavation work can create opportunities for water intrusion if flood protection measures are not consistently used. Con Edison has already developed operational protocols that require crews working on open excavation sites to secure them to minimize water intrusion risk.

Water intrusion into gas regulators through aboveground vents may also cause damage. This intrusion could lead to water sitting on top of the diaphragm that allows each regulator to function and exerting additional pressure on the diaphragm that could, in turn, over-pressurize the regulator. Over-pressurized gas flowing through a system designed for lower pressure gas increases the possibility of tearing leaks in distribution piping, and in the worst-case scenario, could blow out pilot lights.

For the gas distribution system to function at full capacity and to be able to provide customers with desired gas supply, Con Edison must keep gas moving through the system at the intended flow rate, or pressure level, of each system segment. Once water enters the gas system, it is difficult to pinpoint the location and remove the water, which can increase the durations of resulting service interruptions.

Con Edison is currently undertaking several measures to manage underground water intrusion:

- Using drip pots to collect water at low points in the system (approximately 8,000 are currently in place)
- Developing a program to better prioritize gas infrastructure replacements. Remote sensors and machine learning could identify leak-prone areas to prioritize for upgrades intended to mitigate increasing precipitation risks in the face of climate change
- Developing a drip pot remote monitoring program using sensors, which would increase the efficiency of periodic emptying of drip pots and reduce the effort needed to monitor drip pots during the period of planned pipe replacement
- Shifting toward constructing and repairing infrastructure with more leak-resistant equipment, when possible

A climate change-driven increase in the frequency and intensity of flood events, such as heavy rain events or snow events followed by rapid snow melt, or coastal storm surge, may elevate the risk of water infiltration into the low-pressure gas system. The precipitation threshold currently used as a benchmark for monitoring and emptying drip pots is ½ inch of rain in 24 hours. Under the RCP 8.5 scenario, this threshold is projected to be exceeded 37 days per year in Central Park by the latter part of the century, which is nearly 20% more than the 31 days observed over the baseline period.

Low-probability, high-impact extreme events may also include heavy rainfall and storm surge that could increase the risk of water entering the distribution system. An increase in the frequency and intensity of extreme events may make water infiltration into the gas distribution system more likely. Con Edison's gas

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system has established criteria to ensure that new equipment, such as gas regulator line vents, is resilient against a 100-year storm and 1 foot of sea level rise. After Superstorm Sandy, Con Edison upgraded two regulator stations to meet this standard. The Study team determined that to protect regulator stations against 3 feet of sea level rise, Con Edison would need to update 32 regulator stations, at a cost of $13.8 million.

The gas transmission system is vulnerable to cold snaps associated with nor'easters, when temperatures can drop below 0°F for multiple days. Transmission system capacity is designed to meet demand projected for weather conditions at or above 0°F. Temperatures below that threshold may increase demand to a level that exceeds system capacity; in such an event, system pressure may decrease, resulting in customer service loss.

In a generally warmer climate, the gas sector could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by 2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 144 MMdt in 2050, compared to the base case.

Adaptation Options for the Gas System

In addition to Con Edison's existing efforts, the Study team identified several additional adaptation options that the company could consider. Some measures proposed, such as remote information monitoring and analysis, address vulnerabilities in operations and planning processes. Most measures proposed address physical vulnerabilities (see Table 7), which fall within the "withstand" adaptation category.

In the short term, Con Edison could focus on expanding its monitoring capabilities, particularly through programs that use machine learning and remote monitoring to identify vulnerable areas of the distribution system, and remote drip pot monitoring sensors.

To account for changing temperatures, Con Edison could integrate climate change data on changes in the winter gas TV into gas volume and peak load forecasting so that the company is continuously planning for future changes in climate.

To address physical risks to existing infrastructure, Con Edison may need to invest in the system at strategic points in time, as described in Table 7.

Distribution system measures focus on minimizing the risk of flood water entering and depressurizing gas mains and pipes, and measures to more easily re-elevate pressure if water does enter the system.

Adaptation measures identified to address transmission system vulnerabilities primarily focus on diversifying the system and strengthening load management when capacity is constrained.

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Table 7 ■ Physical adaptation options for gas commodities

Hazard	Asset	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Extreme Hurricane (Category 4)	Transmission System	Procure additional compressed natural gas tank stations.	Designing for a future Category 4 hurricane	Increased frequency and severity of storms that could cut supply, including from science-based projections
	Gas Regulators	Install vent line protectors, extend vent lines and posts, seal all penetrations, and/or elevate key electric and communications equipment to protect vent lines.	2050	When sea level rise exceeds 1 foot, or if flooding is reported and the regulators do not have vent line protectors
	Distribution System	Continue targeted Main Replacement Program (planned completion by 2036) to harden gas mains against depressurization by water intrusion or other concerns.	~2030 (goal to complete program by 2036)	Increase in flooding events
Extreme Nor'easter	Transmission System	Construct additional gate stations.	Designing for a future worst-case nor'easter	More frequent or intense cold spells that drop temperatures below the design threshold for consecutive days and threaten supply
		Build larger and/or additional transmission mains.		
		Create ties between mains to diversify the transmission system.		
		Install remote operated valves to more efficiently isolate load for load management (temporarily disconnecting gas customers) during peak events.		

In addition, given the increasing potential for extreme events, Con Edison could consider distribution system resilience options such as exploring and implementing ways to elevate system pressure in low-flow conditions.

Steam System

Steam System Overview

Con Edison's steam system provides service to more than 3 million Manhattan residents (including approximately 1,720 metered customers) south of 96th Street. Total system capacity is about 11,676 thousand pounds per hour (Mlb/hr). The distribution system is comprised of a continuous network of pipes (steel main pipes and steel and brass service and condensate piping)—in aggregate, about 105 miles of piping. The pipes' physical location is directly correlated with the locations of generation sources and regional customer demand. Figure 21 shows the locations of several steam system assets.

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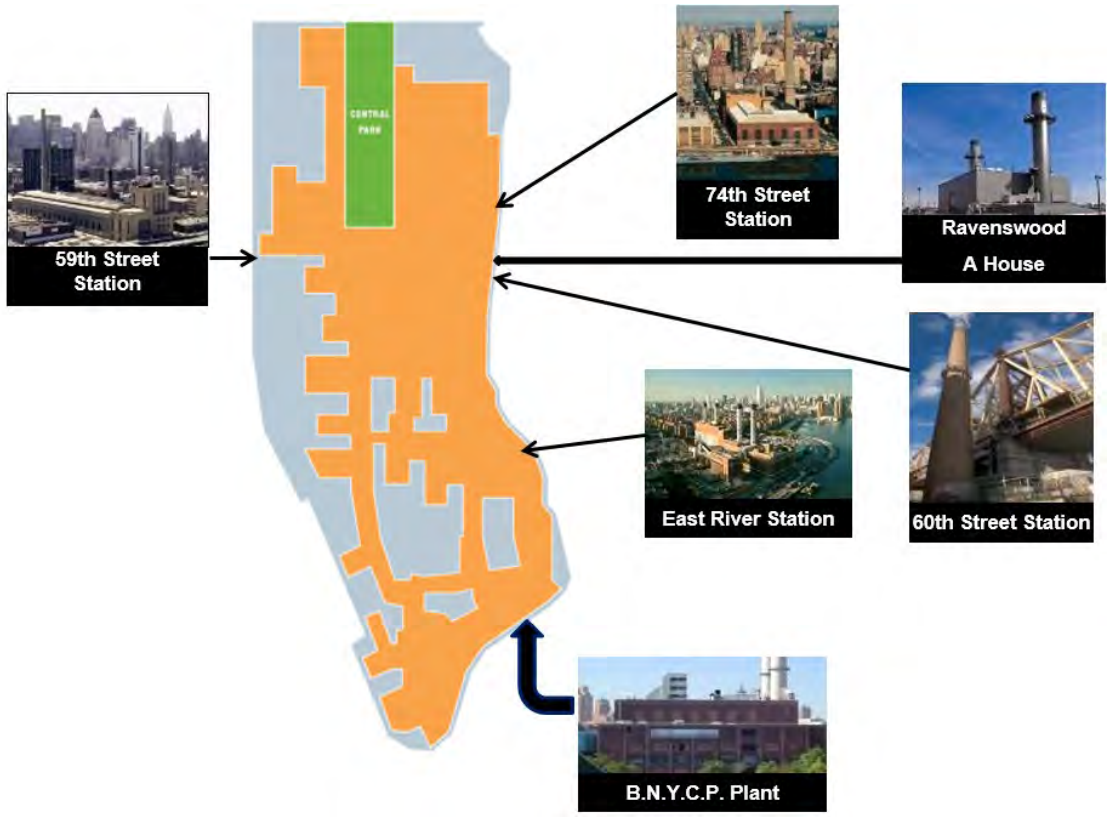
Figure 21 ■ Key assets included in the Con Edison steam system



Steam Vulnerabilities

Like the gas system, much of Con Edison's steam system is underground, and steam is also a winter-peaking rather than a summer-peaking commodity. As such, steam generation and distribution assets are generally less prone to damage by shifts and extremes in temperature, humidity, and wind, and more vulnerable to flooding, which may be caused by increased precipitation, coastal inundation, snow melt, or storm surge in extreme events. Severe flooding impacts, such as broken distribution pipes and damaged steam generation stations, can take significant time to repair, further increasing the duration of customer impacts.

Increased frequency and intensity of precipitation events may increase the vulnerability of steam system manholes to "water hammer" events. When a high volume of water collects around a manhole, steam in the pipes underneath may cool and condense. Interaction between steam and the built-up condensate may cause a rupture in a steam pipe. One such water hammer event occurred in 2007 when a steam pipe at Lexington Avenue and 41st Street exploded during a period of heavy rainfall (Figure 22). Con Edison responded to that event by implementing a precautionary rain event threshold. If more than ¾ inch of rain is forecasted to fall within 3 hours, Con Edison will begin to proactively monitor and address flooding before it can cause a water hammer event. The key measure used to address flooding to prevent water hammer events is pumping water out of manholes and into the city sewer. In turn, Con Edison's capacity to manage flooding events that threaten steam generation and distribution assets depends on the capacity of the city's stormwater

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system to handle high volumes of water that Con Edison may need to pump away from assets under a changing climate.

Steam generation and distribution system assets are also vulnerable to projected increases in sea level and coastal inundation. Five out of six steam generating plants would be exposed to a 100-year storm if sea level rose by 3 feet. If water enters the steam generation system, it can degrade plant capacity or force unit or plant outages. Significant damage to steam generation systems would likely require long repair times, which could increase the duration of customer impacts. Hardening several of the generating stations to a higher level of protection would be difficult and costly. For example, at the East River Generating Station, raising mechanical equipment would require significant and costly alterations to the hydraulics of the steam system. Similarly, at East 13th Street, flood waters associated with a 100-year storm and 3 feet of sea level rise would reach the tertiary bushings on some 345-kV transformers, resulting in arcing and critical failure of the unit. The total estimated cost to harden the five steam generation plants against a 100-year storm and 3 feet of sea level rise is $30 million.

Figure 22 ■ 2007 steam pipe explosion

Con Edison has adopted storm hardening measures to protect the steam system in response to recent storms such as Superstorm Sandy. Those measures include developing location-specific plans and drills in preparation for storms, implementing physical hardening measures at steam generating stations, protecting critical equipment by waterproofing or relocating it, installing a new steam main to ensure that hospitals receive continued service, and introducing isolation valves in strategic locations to reduce the number of customers impacted by flooding in future extreme events. Because isolating steam lines is key to managing flooding impacts, Con Edison considers several potential flood sources (e.g., rainfall deluges, storm tides, water main breaks) when evaluating hardening options, and periodically reviews and updates both operational and physical risk mitigation strategies. The company is also investing in steam system resilience through measures such as waterproofing system components in the normal course of upgrades, prioritizing hardening steam mains by prior flooding issues (fewer than 10 of the original 86 locations identified are still vulnerable), and using remote monitoring to monitor manhole water level and steam trap operation (a system is currently under design and expected to be operational by 2021).

Extreme and multi-hazard events could also increase the vulnerability of the steam distribution system to salt damage and flood damage. During nor'easters and extreme ice storms, the City of New York and jurisdictions in Westchester County conduct widespread street-salting operations to mitigate ice build-up on roads and sidewalks. Rapid melt after nor'easters and extreme ice storms can lead to an influx of salt-saturated runoff into manholes, in turn causing equipment degradation and, in some cases, manhole fires or explosions.

In a generally warmer climate, the steam system could experience significant decreases in winter energy sales for heating. There could be up to a 33% decrease by 2050 and a 49% decrease by

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2080. Similarly, under the RCP 8.5 scenario, winter gas peak load is projected to decrease by 891 Mlb/hr in the winter of 2050 compared to the base case.

Adaptation Options for the Steam System

To determine when to implement various adaptation strategies, Con Edison could track climate trends, including TV, precipitation, sea level rise and storm surge, and extreme events, as described in prior vulnerability and adaptation sections.

The Study team suggests that Con Edison could continue to work collaboratively with other city actors on initiatives that could help strengthen the resilience of the steam system. Specifically, the company could take measures, including the following:

- Strengthen collaboration with the city to improve citywide stormwater design to alleviate flooding impacts and make adaptation measures implemented by Con Edison, such as drain pumps at manholes, more effective.
- Discuss ways to minimize salt use during the winter.
- Incorporate considerations of New York City initiatives in coastal resiliency plans for lower Manhattan to re-evaluate Con Edison's storm response plans and stages of pre-emptive main shutoffs.

In addition to engaging in these monitoring and coordination efforts, the company could also consider taking measures to address physical vulnerabilities in existing infrastructure by strategically investing in the system. Physical measures developed by the Study team are listed in Table 8.

Table 8 ■ Physical adaptation options for steam commodities

Hazard	Asset	Adaptation Option	Implementation Timeframe	Signpost or Threshold
Extreme Hurricane (e.g., Category 4)	Generation System	Invest in additional storm hardening investment measures to protect generation sites against extreme hurricane-driven storm surge. Leverage new innovations and advancements in flood protection over time and raise moated walls around current generation sites.	2050	When sea level rise exceeds 1 foot
	Distribution System	Continue to segment the steam system to limit customer outages in flood-prone areas.	In preparation for a Category 4 hurricane	Increased frequency and severity of storms, including from science-based projections
	Distribution System	Expand programs to harden steam mains (waterproofing pipes and raising mains).	In preparation for a Category 4 hurricane	Increased frequency and severity of storms, including from science-based projections
		Pre-stage a greater number of drain pumps at critical or flood-prone manholes.		

As it is neither practical nor feasible for Con Edison to build resilience to the point that its steam system can fully withstand the impacts of extreme events, Con Edison could also consider implementing additional strategies to better absorb and recover from impacts, such as improving systems for crowd-sourcing steam system leak detection.

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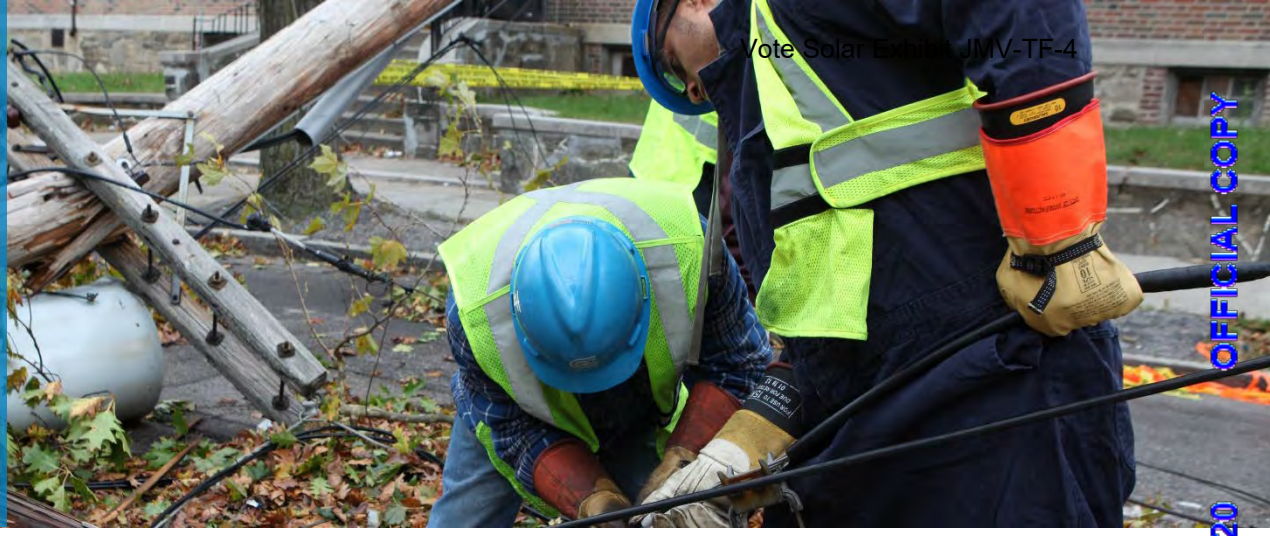

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Moving Towards Implementation

Initial Climate Projection Design Pathway

Implementation of adaptation options to mitigate vulnerabilities requires clear climate design guidelines that incorporate forward-looking regional climate change projections. To this end, the Study team suggests that Con Edison could establish an "initial climate projection design pathway" that considers appropriate risk tolerance levels within the range of climate change projections. The initial climate projection design pathway is meant to guide preliminary planning and investments until and if Con Edison can refine the pathway to reflect new climate projections with reduced uncertainties, changes to Con Edison's operating environment, and changes in city guidance. The following section outlines an adaptive management approach that allows Con Edison to monitor, manage, and design to acceptable levels of climate risk through time.

As an initial climate projection design pathway for decisions that require it, Con Edison will follow the conservative precedent set by the city's climate resiliency design standards (e.g., Mayor's Office of Recovery and Resiliency, 2019), combined with the state-of-the-art climate projections produced for this Study. Corresponding to city guidance, the same pathway may not apply uniformly across different climate change projections and hazards. More specifically, multiple climate projection design pathways may be required to address differences in the risk tolerance and projection uncertainty associated with different climate hazards. Under this framework, initial pathways could use the 50th percentile merged RCP 4.5 and 8.5 projections for sea level rise and high-end 90th percentile merged RCP 4.5 and 8.5 projections for heat and precipitation. Climate projection design pathways will be finalized for Con Edison's Climate Change Implementation Plan.

Alternative considerations are necessary to inform pathways for rare and difficult-to-model extreme events without probabilistic projections, such as 1-in-100-year heat waves and strong, multi-faceted hurricanes. Rather than prescribing statements of probability, these types of extremes require the blending of plausible worst-case scenarios from a climate perspective with stakeholder-driven worst-case scenarios from an impact perspective. Until climate modeling can better resolve and simulate these types of rare extreme events, the union of these two perspectives is critical for determining acceptable risk tolerance levels and setting initial pathways.

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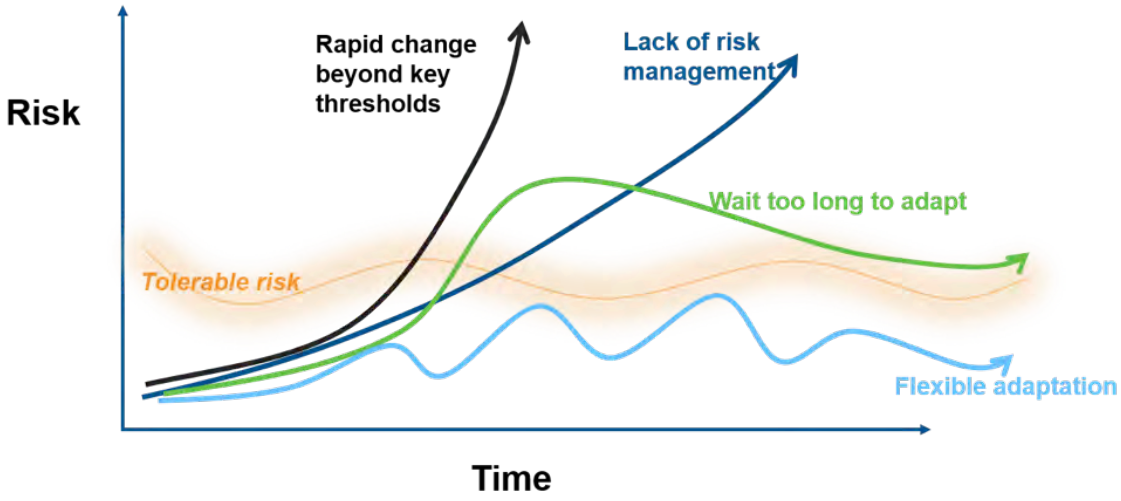
Flexible Adaptation Pathways Approach

While the initial climate design pathway can inform asset design, a complementary approach is needed to ensure resilience over the lifetime of that asset. A flexible and adaptive approach will allow Con Edison to manage risks from climate change at acceptable levels, despite uncertainties about future conditions. The flexible adaptation pathways approach ensures continued adaptability over time as more information about climate change and external conditions is learned. Figure 23 depicts how flexible adaptation pathways are used to maintain tolerable levels of risk.

Figure 23 ■ Flexible adaptation pathways in the context of tolerable risk and risk management challenges to non-flexible adaptation. Adapted from Rosenzweig & Solecki, 2014.



Con Edison will need to consistently track changing conditions over time to identify when additional adaptation strategies are required. This approach relies on (1) monitoring indicators ("signposts") related to climate conditions, climate impacts, and external conditions that affect system resilience, and (2) pre-determined thresholds to signal the need for a change in risk management approaches ("transformation points"). This approach can support decisions on when, where, and how Con Edison can take action to continue to manage its climate risks at an acceptable level. Figure 24 depicts how a signpost indicator and a predefined threshold can be applied in the adaptation pathways approach to inform the timing of action given uncertainty.

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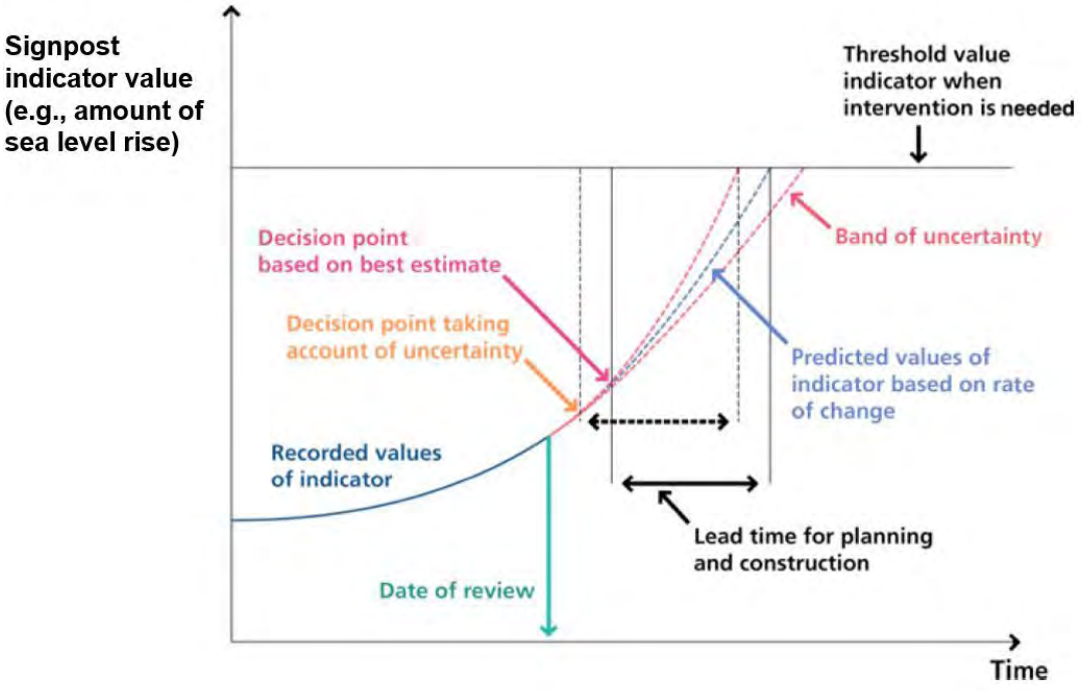
Figure 24 ■ Schematic diagram of how an indicator of change for a particular signpost (e.g., amount of sea level rise) informs decision lead times that take into account uncertainty (Ranger et al., 2012).



Con Edison is already familiar with monitoring signposts to manage planning uncertainties and guide adjustments to its Electric, Gas, and Steam Long Range Plans.[20] Con Edison currently monitors signposts related to the pace of technology innovation (e.g., energy management technologies), the nature of regulation and legislation (e.g., new or revised greenhouse gas reduction policy targets), and the future of the economy (e.g., higher economic growth and impacts on demand), among others. In addition, the flexible adaptation pathways approach to manage climate change risks has been applied more widely by New York City and New York State (New York City Mayor's Office of Resiliency, 2019; Rosenzweig & Solecki, 2014) and utilities and infrastructure agencies across the United States, including San Diego Gas & Electric (Bruzgul et al., 2018; SDG&E, 2019) and Los Angeles Metro (Metro ECSD, 2019).

This flexible adaptation pathways approach allows Con Edison to develop an adaptation implementation plan in the near term, while adjusting adaptation strategies based on the actual climate conditions that emerge, thus reducing the cost of managing uncertainty. Under this adaptive approach, resilience measures can be sequenced over time to respond to changing conditions. For example, Con Edison may identify actions to implement now that protect against near-term climate changes and actions that are low and no regret, while leaving options open to protect against the wide range of plausible changes emerging later in the century. This implementation approach is preferred to implementing actions now that are optimized for present-day conditions or a single future outcome that ignores uncertainty.

[20] Long Range Plans are available at: https://www.coned.com/en/our-energy-future/our-energy-vision/long-range-plans

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Illustrative Adaptation Pathway: Sea Level Rise Adaptation for Substation in FEMA + 3' Floodplain

Flexible adaptation pathways could be developed for guiding the management and protection of specific assets or types of assets. Here, we consider a hypothetical electric substation that is potentially vulnerable to sea level rise, as it is located within the FEMA + 3' floodplain (and, as such, is protected up to FEMA + 3' flood heights based on Con Edison's current design standards). This adaptation pathway is presented as *illustrative*; while it is grounded in the types of strategies that Con Edison would use for substation flood defense, a ready-to-implement pathway for implementation would require site-specific analysis and may differ from this configuration.

Figure 25 ■ Illustrative flexible adaptation pathway for a hypothetical Con Edison substation in a current FEMA + 3' floodplain

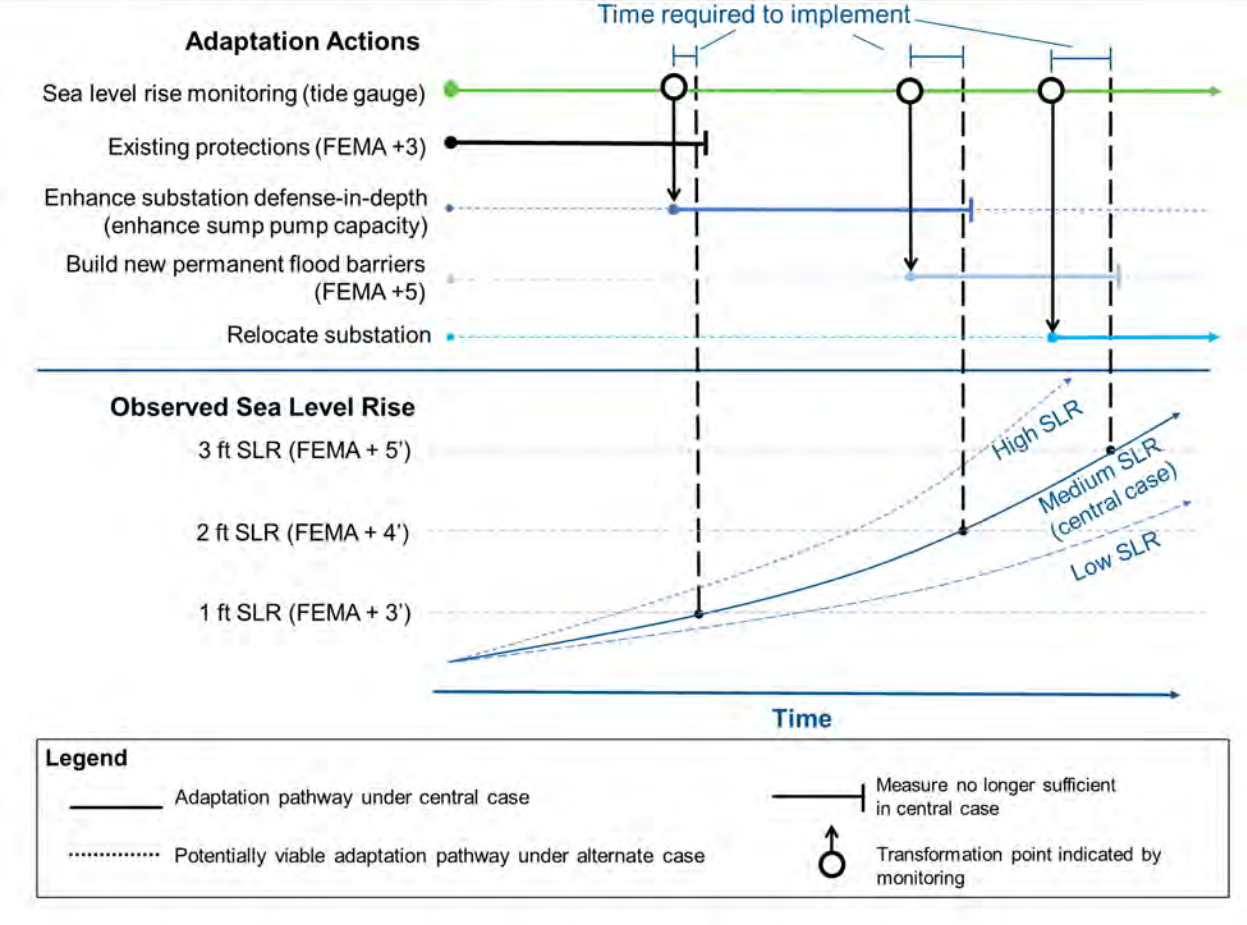

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Figure 25 illustrates how the implementation of adaptation actions can be phased over time, with the implementation of new measures being triggered by observed sea level rise in excess of certain thresholds (transformation points). The timing of these transformation points is indicated by monitoring the rate of sea level rise at a local tide gauge (green line). Transformation points are set based on the point at which Con Edison needs to take action in order to implement a higher standard of protection before existing protections become insufficient.

In this adaptation pathway diagram, the implementation schedule of adaptation measures is illustrated based on a "central" sea level rise case. Measures based on this central scenario are illustrated with solid lines. If the actual pace of sea level rise deviates from the central case, monitoring of sea level rise may necessitate an accelerated or delayed implementation schedule

In this example, it is assumed that the substation already has existing protections to FEMA + 3' based on Con Edison's post-Superstorm Sandy hardening measures (black line). However, these protections will no longer be sufficient to provide the requisite 2 feet of freeboard under a 100-year flood scenario once sea level rise surpasses 1 foot.

- A trigger slightly under 1 foot leads to the first adaptation option, which is to supplement the substation's defense-in-depth strategy with additional sump pump capacity.
- The second adaptation option is triggered when sea level rise approaches 2 feet, and includes building new permanent flood barriers to a FEMA + 5' level.
- The final adaptation option, relocating the substation entirely, is triggered when sea level rise approaches 3 feet.

Each trigger is far enough in advance of the critical risk threshold (each foot of sea level rise, in this case) to have time for full implementation of the adaptation option.

Such a flexible adaptation pathway can allow Con Edison to better manage the costs of adaptation in the face of uncertainty, facilitating a prudent approach that avoids adapting too early or too late.

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Signposts provide information that is critical for adaptive management decisions. Broad categories of signposts that Con Edison could consider monitoring include:

- **Climate variable observations and best available climate projections:** An awareness of recent and present climate conditions and their rates of change are key when determining potential asset exposure and risk. As described above, Con Edison currently operates a number of stations that monitor climate variables and is finalizing plans to expand the number of monitoring locations. Furthermore, access to the most recent and best available climate projections and expert knowledge is critical when updating plans for potential future scenarios as the science advances. In some cases, thresholds for action under climate variable and projection signposts may be determined by how quickly changes in climate conditions are approaching existing design or operational specifications.
- **Climate impacts:** Con Edison is already experiencing extreme weather and climate impacts to assets, operations and internal processes, and customers. Recognizing the risks, Con Edison is already conducting monitoring to identify areas of heightened vulnerability in its systems. Continued monitoring and evaluation of highest risk assets for impacts or near impacts can provide information about when and where additional adaptation options may be required.
- **Policy, societal, and economic conditions:** Evolving external conditions may affect climate-related decision making and areas of need throughout the service territory. Con Edison is already monitoring signposts for external conditions related to policies, society, and economies as part of its long-range plans. Additional external conditions may shift with a changing climate, such as adaptation strategies and investments led by the city.

The Study team identified a set of example signposts within each category, summarized in Table 9. Con Edison could consider coordinating with the city on NPCC's proposed New York City Climate Change Resilience Indicators and Monitoring System (Blake et al., 2019), where overlap and efficiencies in monitoring signposts may exist.

Table 9 ■ Example signposts for a flexible adaptation pathways approach

Category	Example Signposts
Climate variable observations and best available climate projections	• *Chronic variables:* Rate of change in TV, cooling degree-days, heating degree-days, sea levels, etc. relative to historical • *Extreme weather variables:* Number of days overheat index thresholds, storm surge levels, frequency of various storm types in the greater region, wind speeds, heat wave intensity and duration, intense precipitation levels, etc. • Updates to the best available climate projections: NPCC, IPCC, National Climate Assessment, etc.
Climate impacts	• *Assets:* Extent and magnitude of the costs of keystone asset damages (e.g., substations or power lines downed), damages incurred by events with different combinations of extreme weather, etc. • *Operations and internal processes:* Frequency of heat-related contingencies in the network and non-network systems, etc. • *Customers:* Number, spatial extent, and duration of outages caused by extreme weather, especially noting outages experienced by critical infrastructure and interdependent systems, etc.
Policy, societal, and economic conditions	• *Policy:* Updates to New York City design guidelines, etc. • *Societal:* Community-scale flood protection strategies led by New York City (e.g., East Side Coastal Resiliency Project), population shifts (e.g., retreat), etc. • *Economic:* Insurance prices and availability, etc.

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Selecting Cost-Effective Solutions

As outlined in this Study, adapting to climate change will require investments in infrastructure and processes. Although some adaptation will be achieved through co-benefits from investments that Con Edison makes under existing processes, such as using distributed energy resources to meet growing electricity demand, other adaptation will require investments over and above those previously planned. The costs of those investments will ultimately be reflected in customers' bills. In order to minimize the financial impact of adapting to climate change, a cost-effective resilience planning process should identify a target level of resilience along with associated metrics, strike a balance between proactive and reactive spending, consider both the costs and benefits to customers, and select adaptation strategies that provide optimal benefit at the lowest cost.

As the energy industry grapples with how best to build resilience to the changing climate, the issue of how to quantify the resilience of energy systems is front and center. There is currently no standard *set of metrics* for the resilience of energy systems. A 2017 report from the National Academies of Sciences, Engineering, and Medicine found that "there are no generally agreed-upon resilience metrics [for the electricity sector] that are widely used today," also noting a contrast with the well-established set of electricity reliability metrics (NAS, 2017).

While there are a wide variety of energy resilience metrics that have been proposed or piloted in various contexts, most of these metrics fit within one of two broad categories. *Performance-based* metrics seek to quantify the resilience of the system through measurement of infrastructure performance during actual or modeled disruptive events. *Attribute-based* metrics, on the other hand, measure the presence of characteristics or features that are known or predicted to increase resilience performance in the event of a disruption. (Vugrin, Castillo, & Silva-Monroy, 2017).

Con Edison's storm hardening investments after Superstorm Sandy were guided by a combination of performance-based metrics, such as "past performance" in the selective undergrounding of feeders, and attribute-based metrics, such as "reducing the number of customers served by a single circuit to fewer than 500 customers," and adding "isolation devices to spurs and sub-spurs with open wire that are more than 2 spans in length" (Con Edison, 2013). Since the development of metrics is an active area of research and discussion, Con Edison could keep abreast of industry advances in resilience metrics for energy systems and incorporate those advances, where applicable, into its planning framework.

Even after a resilience metric(s) is selected, the question of exactly *how much* to spend on resilience or what the *right* level of resilience is, remains. One approach is to compare the societal cost of an outage against the cost of resiliency measures to shorten that outage. The total cost curve developed by ICF's Mihlmester and Kumaraswamy (Figure 26) is one example of such an approach (Mihlmester & Kumaraswamy, 2013). It shows for a hypothetical utility the post-outage time needed to restore service to 90% of customers, known in the industry as "CR-90." In this case, the lowest total costs, combining customer outage and grid-hardening costs, would be about $169 million for a 65-hour CR-90 restoration time. The graph also shows that getting the CR-90 time to less than a day would cost more than twice that amount.

For Con Edison, the "right" level of resiliency investment will be strongly linked to the climate projection design pathway selected for each of the climate stressors identified for resiliency planning.

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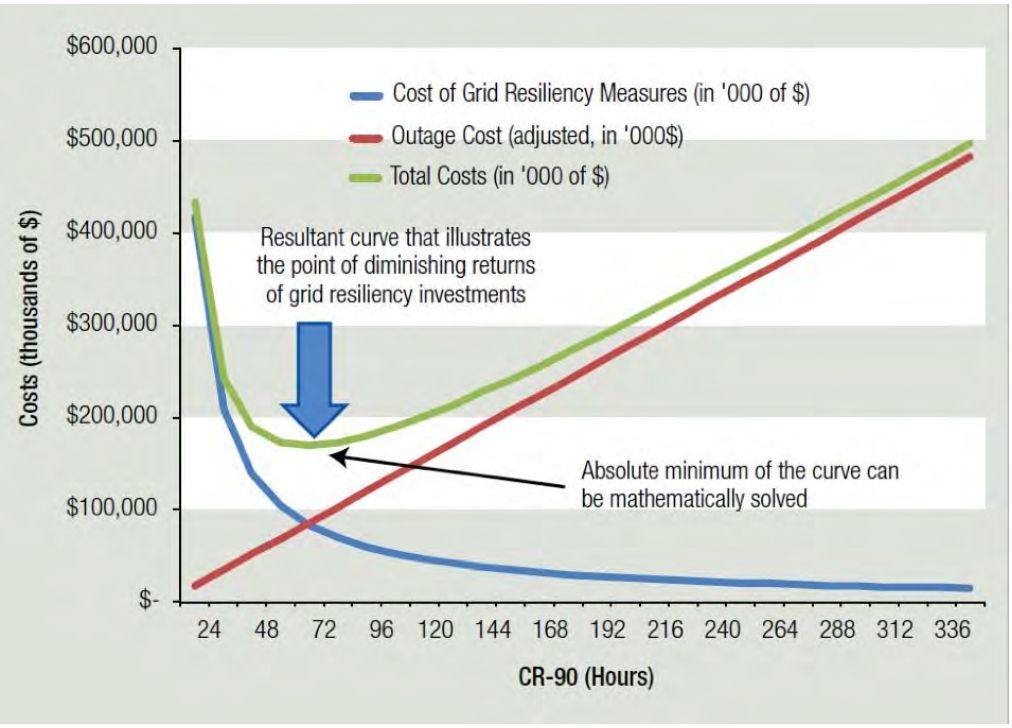
Figure 26 ■ Total cost of resiliency (Mihlmester & Kumaraswamy, 2013)



Utilities have historically *reacted* to events, primarily because they lacked relevant climate projections and clear guidance or best practices for a methodology necessary to inform *proactive* adaptation and resiliency investments in infrastructure (California Energy Commission, 2018). Similarly, prior to conducting this study, Con Edison had limited information to guide proactive investments. The U.S. Department of Energy's North American Energy Resilience Model (U.S. DOE, 2019) highlights the need to "transition from the current reactive state-of-practice to a new energy planning and operations paradigm in which we proactively anticipate damage to energy system equipment, predict associated outages and lack of service, and recommend optimal mitigation strategies."

The Study team has described an overarching resilience management framework in Figure 12, designed to minimize the impacts of extreme events throughout asset life cycles. The framework considers how the system can withstand, absorb, recover, and adapt to risks posed by extreme events. To succeed, each measure of a resilient system requires *proactive planning and investments*.

Consideration of the *costs and benefits to customers* is a key component in the selection of adaptation options. Con Edison's capital budget cycle currently considers costs and benefits through an investment optimization and management process that compares the wide array of capital investments the company makes across its various business units. The process calculates a "strategic value" for each project to compare the benefit of investing in one capital project or program over another and to ensure that spend is in alignment with the company's corporate strategy. The strategic value is conveyed by a set of strategic drivers, each with relative weights, based on the company's long-term objectives. The strategic value of each capital project is assessed against that of other projects, and an optimized portfolio of capital projects is generated. While the strategic drivers include *reliability* and customer satisfaction components, the drivers do not include or consider the *resiliency* benefit of a project.

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Con Edison developed and used a cost-benefit calculation model to prioritize storm hardening investments after Superstorm Sandy. The model estimated "the vulnerability of individual electric system assets based on the impact of electric system damage to customers and supporting critical infrastructure, the duration of an electric service outage, the likelihood of those assets being affected by either flooding or wind damage, and the reduction in vulnerability of those assets because of storm hardening initiatives." (Con Edison, 2014)

Con Edison's current distribution system planning process includes an evaluation of customer benefits resulting from investments. Con Edison's Distributed System Implementation Plan (DSIP) (Con Edison, 2016) includes the consideration of distributed energy resources as one option to meeting growing demand. As part of Con Edison's DSIP, the company has developed a Benefit Cost Analysis (BCA) Handbook that describes how to calculate individual benefits and costs. The BCA includes consideration of the unit cost of a particular option, per megawatt of delivery capacity, as well as an option's "social cost." Social cost accounts for the monetization of air pollution and carbon dioxide, using 20-year forecasts of marginal energy prices, the cost of complying with regulatory programs for constraining these pollutants, and the price paid for renewable energy credits. The social cost metric also qualitatively accounts for avoided water and land impacts. Beyond these environmental aspects, social cost accounts for net avoided restoration and outage costs to Con Edison, as well as net non-energy benefits (such as avoided service terminations, avoided uncollectable bills, and avoided noise and odor impacts).

This Study illustrates the use of multi-criteria analysis to compare criteria that may be difficult to quantify or monetize, or that may not be effectively highlighted in the financial analysis. This process identified additional complementary metrics that could be included in Con Edison's planning and budget prioritization process to account for uncertainty in climate outcomes. These metrics fall into two categories: co-benefits and adaptation benefits. Under a non-stationary climate, co-benefits (environmental, reputational, safety, and customer financial benefits) can help planners more comprehensively evaluate response options considering the additional challenges that climate change can pose on the system. In addition, consideration of adaptation benefits (flexibility, reversibility, robustness, proven technology, and customer's resilience) support long-term planning under climate uncertainty. These metrics allow for effective implementation of adaptation measures over time to achieve resilience. Con Edison's current processes include some of the metrics identified in the multi-criteria analysis (environmental and safety) but not others (customer's resilience and reversibility). Con Edison could work to incorporate this wider set of metrics as it incorporates resiliency planning into its broader capital budgeting process.

Key Issues to Be Addressed for Effective Implementation

Changes in the Policy/Regulatory and Operating Environment

Changes in the policy/regulatory and operating environment other than climate change were not accounted for in this Study but will be an important consideration when moving toward implementation. For example, the prioritization of adaptation strategies, and even the understanding of vulnerabilities, will need to consider these other drivers of change. Likewise, as Con Edison undertakes studies on how these factors will impact its business, climate change impacts could be factored into those studies. Some examples of possible changes in Con Edison's operating environment include:

- **Climate change and clean energy targets:** New York State and New York City have both adopted ambitious greenhouse gas emissions reduction targets (State of New York, 2019; City of New York, 2014), which will drive changes in the adoption of renewables, transportation electrification, energy storage, and

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so forth. It will also impact relative demand across the commodities (e.g., decreasing gas demand and increasing electricity demand).

- **Technological advances:** Advances in solar photovoltaics, energy storage, electric vehicles, and electrification of space heating are changing how and where electricity is generated and used.
- **Customer response to climate change impacts:** Customers will also have to respond to climate change impacts. This may include shifting away from flooded coastlines (depending on city-scale investments in coastal protection) and, with it, shifting demand away from portions of Con Edison's system.

Coordination with External Entities

Another critical need for effective implementation is coordination with external entities, including the City of New York and Westchester County, industry groups, equipment manufacturers, and others. Con Edison has limited authority to address certain vulnerabilities, such as the capacity of the city's stormwater system, so coordination is necessary for developing a more resilient system. In addition, coordination is needed to ensure that Con Edison is not over-investing in locations that the city plans to protect or retreat from. This project seeded the necessary relationships; however, the continuation of the interactions will need to be specified in the governance section of the upcoming implementation plan.

Establishing a Reporting and Governance Structure

Con Edison will need a continuing approach to updating stakeholders on climate risk management progress. Of the various reporting options, many companies are opting to follow the relatively new framework outlined by the Task Force on Climate-Related Financial Disclosures (TCFD).[21] This framework emphasizes the need to assess both the physical risks of climate change, which is covered in this study, as well as the risks and opportunities presented by transition to a low-carbon economy. It requires consideration of the financial implications of the risks and opportunities, as well as a measurable risk management plan that is integrated with a strong governance structure.

Two risks that were not explored in this study, but would fit well in the TCFD framework, include:

- **Costs and penalizations from service failure and outages:** Costs associated with an outage event include restoration; collateral damage; customer claims; penalties, fines, audits, remediation, and reporting; and the financial impact of lost confidence. For example, in 2007, Con Edison was penalized $18 million for its 2006 service disruptions, which included a 9-day blackout in western Queens.
- **Credit rating:** Increasingly frequent and intense extreme weather events could also impact credit rating risks and insurance liabilities. Credit rating agencies like Standard & Poor's and Moody's have added "resiliency" as a component of their rating criteria, indicating the relevance of climate risk for creditworthiness (Shafroth, 2016). Similarly, utilities may be increasingly choosing to retain a higher level of insurance to cope with more frequent and destructive weather-related events. However, a higher level of insurance protection leads to higher costs that may ultimately be reflected on customers' bills. Thus, while not as visible as physical asset or planning vulnerabilities, climate risks related to credit and insurance can have an impact on the utility.

Establishing a governance structure will be crucial for the successful continuation of Con Edison's climate change adaptation work. The governance structure can be used to encourage and track progress on the implementation of adaptation strategies (i.e., performance against set metrics and targets), ensure specific

[21] For more information on the Task Force on Climate-Related Financial Disclosures, see https://www.fsb-tcfd.org/

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people are on point for monitoring and implementing various strategies, and establish a frequency and process for reporting on risks and adaptation actions from individual employees to senior managers to Con Edison's board of directors.

Next Steps

As a next step from this Study, Con Edison will develop a detailed Climate Change Implementation Plan to operationalize the suggestions from this Climate Change Vulnerability Study. The implementation plan will:

- Review the Study and investigate whether recent progress in climate science may warrant inclusion.
- Select climate change pathway(s) to incorporate into design standards and procedures.
- Establish life cycle tables that provide timeframes of reference climate variables through 2080.
- Aggregate input from subject matter experts on changes required for specifications/procedures and choices for risk mitigation measures.
- Develop a timeline and written plan for the implementation of risk mitigation measures.
- Identify the scope and cost within the 5-year capital plan and 10- and 20-year long-range plans.
- Establish signposts for the re-evaluation of measure installation schedules.
- Conduct periodic progress meetings for external stakeholders.
- Recommend a governance structure for climate change monitoring and updating.

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APPENDICES

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Appendices

To inform the conclusions of this Study, the Study team undertook a series of in-depth vulnerability assessments corresponding to the climate hazards representing outsized risks to Con Edison: temperature, humidity, precipitation, sea level rise, and extreme events. These are included as appendices. Each appendix includes detailed historical and projected climate conditions; corresponding climate-driven vulnerabilities to operations, planning, and infrastructure across the company's electric, gas, and steam systems; and potential adaptation strategies to mitigate vulnerabilities.

For each hazard, the Study team collaborated with Con Edison subject matter experts to conduct a rapid screen of the sensitivity of operations, planning, and infrastructure to support a risk-first approach. Vulnerabilities were then selected for more detailed analyses, which focused on understanding asset vulnerabilities to climate change and, in turn, relevant adaptation options and evaluation of their costs and co-benefits. These analyses informed the development of flexible solutions and signposts to guide implementation of potential adaptation options through time.

Ultimately, the five appendices provide key context for the climate science, vulnerabilities, and adaptation strategies discussed in this report, and as such, can be referenced for more comprehensive information in each subject area.

- **Appendix 1 – Temperature:** Identifies how projected gradual trends in increasing temperature may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 2 – Humidity, Temperature Variable, and Load:** Addresses climate variables—humidity (expressed through wet bulb temperature), heat waves, cooling degree-days, heating degree-days, and the combination of projected changes in wet and dry bulb temperatures—that have a direct effect on system loads and reliability. These variables are also specifically addressed in specifications and procedures associated with upgrading system capacity and maintaining system reliability.
- **Appendix 3 – Changes in Precipitation Patterns:** Discusses the potential for climate-driven changes in rainfall and frozen precipitation in Con Edison's service territory, and the potential impacts of those changes on Con Edison's assets and operations.
- **Appendix 4 – Sea Level Rise and Changes in Coastal Storm Surge Potential:** Examines the ways in which changes in sea level may affect operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business.
- **Appendix 5 – Extreme Events:** Describes how extreme weather events (hurricanes, nor'easters, and heat waves), as well as concurrent or consecutive extreme events, may become more frequent and severe due to climate change, and considers their potential impact on operations, planning, and infrastructure across the electric, gas, and steam segments of Con Edison's business over the coming century.

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I/A

Direct Testimony of James Van Nostrand and Tyler Fitch
On Behalf of Vote Solar
Docket No. E-7, Sub 1214

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Exhibit JMV-TF-5

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Exhibit JMV-TF-5: Literature Review of Climate-Related Risks

#	Category	Date Published	Source	Author (if relevant)	Title / Link
1	Financial Institution Actions on Climate Risk	January, 2020	Wall Street Journal	Ronald P. O'Hanley, CEO, State Street,	Sustainability Is Part of Good Risk Assessment
2	News & Finanical Reporting Coverage; NC Context	January, 2020	Asheville Citizen-Times	Joel Burgess	Asheville declares 'climate emergency,' looks to end greenhouse gas emissions 2030
3	News & Finanical Reporting Coverage	January, 2020	WFAE	David Boraks	State and Local Leaders Set Climate Goals, But Can We Meet Them?
4	Context in North Carolina	January, 2020	NC Climate Change Interagency Council	Kenneth Kunkel, David Easterling	Presentation of January 22 Meeting
5	News & Financial Reporting Coverage	January, 2020	UtilityDive	Catherine Morehouse	Ameren, Xcel, Dominion, Duke among most at-risk from changing climate: Moody's
6	News & Financial Reporting Coverage	January, 2020	Energy News Network	Allen Best	Tri-State CEO says wholesaler's clean energy transition will pay dividends
7	News & Finanical Reporting Coverage	January, 2020	Charlotte Business Journal	John Downey	Duke Energy ranks high among utilities at risk from hurricanes, other impacts of climate change
8	News & Financial Reporting Coverage	January, 2020	Wall Street Journal	Greg Ip	For the Economy, Climate Risks are No Longer Theoretical
9	Financial Institution Actions on Climate Risk	January, 2020	BlackRock	Larry Fink, CEO, BlackRock	Annual Letter to CEOs
10	Financial Institution Actions on Climate Risk	January, 2020	BlackRock	Larry Fink, CEO, BlackRock	Annual Letter to Clients

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11	News & Financial Reporting Coverage	January, 2020	NYTimes	Andrew Ross Sorkin	Blackrock CEO Larry Fink: Climate Crisis Will Reshape Finance
12	News & Financial Reporting Coverage	January, 2020	Energy and Policy Institute	Joe Smyth	Financial analysts expect decarbonization will benefit utility ratepayers adn shareholders
13	Duke Publications and Statements	January, 2020	Duke Energy Florida	n/a	Amicus Curiae Comments in FPL SolarTogether Petition Proceeding
14	News & Financial Reporting Coverage	January, 2020	POWER	William Friedman	Structural Effects of Climate Change on the Utility Business
15	Technical Analysis	January, 2020	NREL	Reiko Matsuda-Dunn, Michael Emmanuel, Erol Chartan, Bri-Mathias Hodge, Gregory Brinkman	Carbon-Free Resource Integration Study
16	Technical Climate Risk Analysis	January, 2020	McKinsey Global Institute	n/a	Climate risk and response: Physical Hazards and socioeconomic impacts
17	News & Financial Reporting Coverage	January, 2020	Financial Times	Robin Wigglesworth	State Street vows to turn up the heat on ESG standards
18	News & Financial Reporting Coverage	December, 2019	The Atlantic	Robinson Meyer	Investment Bankers are Now Waging the War on Coal
19	Context in North Carolina	December, 2019	North Carolina Clean Energy Technology Center	n/a	Planning an Affordable, Resilient, and Sustainable Grid in North Carolina
20	Financial Institution Scrutiny on Climate Risk	December, 2019	n/a	Robert Litterman, Chair of Climate-Related Risk Subcommittee	Letter to Commodity Futures Trading Commission
21	News & Financial Reporting Coverage	December, 2019	Duke Energy Illumination	Jessica Wells	Lineman's idea leads to microgrid in Great Smoky Mountains National Park
22	Technical Climate Risk Analysis	December, 2019	UN Principles for Responsible Investment	n/a	Impacts of the Inevitable Policy Response on Equity Markets
23	News & Finanical Reporting Coverage	December, 2019	S&P Global	Guarang Dholakia	Duke Energy tops operating US coal, gas capacity ownership
24	News & Financial Reporting Coverage	December, 2019	S&P Global	Jeffrey Ryser	US utilities race to slash emissions as ESG reporting takes off

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25	News & Financial Reporting Coverage	December, 2019	S&P Global	Stephanie Tsao, Richard Martin	Overpowered: What a US gas-building spree continues despite electricity glut
26	News & Financial Reporting Coverage	December, 2019	The Guardian	Julia Kollewe	Coal power becoming 'uninsurable' as firms refuse cover
27	News & Financial Reporting Coverage	December, 2019	LA Times	Sammy Roth	Do PG&E and Edison need higher profits? California is about to decide
28	Technical Climate Risk Analysis	December, 2019	UC Berkeley Law: Center for Law, Energy & Environment	n/a	California Climate Risk: Insurance-based Approaches to Mitigation and Resilience
29	Financial Institution Scrutiny on Climate Risk	December, 2019	International Monetary Fund	Pierpaolo Gripaa, Jochen Schmittmann, and Felix Suntheim	Climate Change and Financial Risk
30	Risk Management Guidance	December, 2019	MJ Bradley & Associates	n/a	Key Considerations for Electric Sector Climate Resilence Policy and Investments
31	Publications from Peer Utilities	December, 2019	Consolidated Edison	n/a	Climate Change Vulnerability Study
32	Risk Management Guidance	November, 2019	UN Principles for Responsible Investment	n/a	Fiduciary Duty in the 21st Century
33	News & Financial Reporting Coverage	November, 2019	Economist	n/a	Firms that analyse climate risks are the latest hot property
34	News & Financial Reporting Coverage	November, 2019	WGBH	Deanna Moran	Utilities--Like Eversource and National Grid--Are Weak Links in Climate Defense
35	Miscellaneous	November, 2019	US Senator Brian Schatz	n/a	Schatz Introduces New Legislation to Ensure U.S. Financial System is Prepared for Climate Change
36	Academic Research on Climate Risk	November, 2019	Swiss Finance Institute	Philipp Krueger, Zacharias Sautner, Laura T. Starks	The Importance of Climate Risks for Institutional Investors
37	News & Financial Reporting Coverage	November, 2019	The Denver Post	Judith Kohler	Tri-State's conflicts with members a factor in the downgrade of its credit rating

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38	News & Financial Reporting Coverage	November, 2019	Bloomberg	Kevin Crowley	Exxon's Credit Rating Oulook Lowered by Moody's on Cash Burn
39	Financial Institution Actions on Climate Risk	November, 2019	European Investment Bank	n/a	EU Bank launches ambitious new climate strategy and Energy Lending Policy
40	News & Financial Reporting Coverage	November, 2019	Risk.net	Tom Osborn	Climate Change Spells Death of Certainty
41	News & Finanical Reporting Coverage	November, 2019	New York Times	Jeanna Smialek	Why the Fed, Long Reticent, Has Started to Talk About Climate Change
42	News & Financial Reporting Coverage	November, 2019	Bloomberg Businessweek	Danielle Moran	Muni Bonds Contain New Fine Print: Beware of Climate Change
43	News & Financial Reporting Coverage	October, 2019	Foreign Times	Masood Ahmed	Disclosure of climate risk will improve decision-making
44	Duke Publications and Statements	October, 2019	Charlotte Observer	Stephen DeMay	Duke Energy NC president: Climate and the case for natural gas
45	Duke Publications and Statements	October, 2019	Utility Dive	Catherine Morehouse	Duke VP likens gas plant buildout strategy to 15-year home mortgage on path to zero carbon
46	Risk Management Guidance	October, 2019	Western Resource Advocates	Aaron Kressig	Damage Control: How Electric Utilities are Planning for Wildfires & the Costs of Climate Change
47	News & Finanical Reporting Coverage	October, 2019	New York Times	Christopher Flavelle	Bank Regulators Present a Dire Warning of Financial Risks from Climate Change
48	Financial Institution Scrutiny on Climate Risk	October, 2019	n/a	Frank Elderson, Chair, Network for Greening the Financial System	Introductory Statement to US Senate Democrats' Special Committee on the Climate Crisis
49	News & Finanical Reporting Coverage	October, 2019	The Royal Gazette	Scott Neil	Axis backs away from coalmine project
50	News & Financial Reporting Coverage	October, 2019	InsideClimateNews	Dan Gearino	Utilities are Promising Net Zero Carbon Emissions, But Don't Expect Big Changes Soon

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51	Context in North Carolina	October, 2019	Noth Carolina Department of Environmental Quality	n/a	North Carolina Clean Energy Plan
52	Financial Institution Scrutiny on Climate Risk	October, 2019	Federal Reserve Bank of San Francisco	n/a	Strategies to Address Climate Change Risk in Low-and Moderate-income Communities
53	Risk Management Guidance	September, 2019	Task Force on Climate-Related Financial Disclosures	n/a	Good Practice Handbook
54	News & Finanical Reporting Coverage	September, 2019	Citizen Truth	Elana Sulakshana	First Major US Insurance Company to Stop Insuring and Investing in Coal
55	Financial Institution Scrutiny on Climate Risk	September, 2019	Majority Action	n/a	Climate in the Boardroom: How Asset Manager Voting Shaped Corporate Climate Action in 2019
56	Regulatory Action on Climate Risk	September, 2019	California Public Utiltiies Commission	Commissioner Liane M. Randolph	Proposed Decision on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation
57	Technical Climate Risk Analysis	September, 2019	Council on Foreign Relations	Amy Myers Jaffe, Joshua Busby, Jim Blackburn, Christina Copeland, Sara Law, Joan Ogden, Paul Griffin	Impact of Climate Risk on the Energy System
58	Technical Climate Risk Analysis	September, 2019	London School of Economics Grantham Research Institute on Climate Change and the Environment	Ruth DeFries et al	The missing economic risks in assessments of climate change impacts
59	Duke Publications and Statements	September, 2019	Duke Energy	n/a	Duke Energy aims to achieve net-zero carbon emissions by 2050
60	Duke Publications and Statements	August, 2019	Duke Energy	n/a	NCUC ISOP Technical Conference Presentation
61	News & Financial Reporting Coverage	August, 2019	Toronto Star	Dianne Saxe	Climate crisis puts corporate boards on the hot seat
62	News & Finanical Reporting Coverage	August, 2019	Raleigh News & Observer	Richard Stradling	NCDOT to lay off hundreds of workers as storms, lawsuits sap its budget

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63	News & Financial Reporting Coverage	August, 2019	Bloomberg	Kelly Gilblom	Big Money Starts to Dump Stocks that Pose Climate Risks
64	News & Financial Reporting Coverage	August, 2019	Utility Dive	Herman K. Trabish	As co-ops struggle with stranded fossil fuel assets, Tri-State may finally embrace the energy transition
65	News & Financial Reporting Coverage	August, 2019	Governing	Liz Farmer	Will Climate Change Lead to a 'Fiscal Tsunami'?
66	News & Finanical Reporting Coverage	August, 2019	InsideClimateNews	Kristoffer Tigue	Climate Change Becomes an Issue for Ratings Agencies
67	News & Financial Reporting Coverage	August, 2019	BusinessGreen	Toby Hill	Climate risk posed by oil, gas, and coal leaves energy investors on shaky ground
68	Risk Management Guidance	August, 2019	Columbia Center on Global Energy Policy	John J MacWilliams, Sarah La Monaca, and James Kobus	PG&E: Market and Policy Perspectives on the First Climate Change Bankruptcy
69	News & Financial Reporting Coverage	July, 2019	Foreign Policy	Adam Tooze	Why Central Banks Need to Step Up on Global Warming
70	News & Financial Reporting Coverage	July, 2019	InsideClimateNews	John Lippert	Could Climate Change Spark a Financial Crisis? Candidates Warn Fed It's a Risk
71	News & Financial Reporting Coverage	July, 2019	Forbes	Jeff McMahon	In Conservative Indiana, Utility Chooses Renewables over Gas as it Retires Coal Early
72	Financial Institution Scrutiny on Climate Risk	June, 2019	Commodity Futures Trading Commission (CFTC)	n/a	CFTC Public Meeting Addressing Climate-Related Risks
73	Financial Institution Scrutiny on Climate Risk	June, 2019	Aspen RE	n/a	Climate Change and the (Re)insurance Implications
74	News & Financial Reporting Coverage	June, 2019	S&P Global	Michael Copley	US regulators examining the financial risk of climate change
75	News & Financial Reporting Coverage	June, 2019	WIRED	Sara Harrison	Companies Expect Climate Change to Cost Them $1 Trillion in 5 Years

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76	NGO Review of Duke Climate Governance	June, 2019	CERES	n/a	Benchmarking Air Emissions of the 100 Largest Electric Power Producers in the Untied States
77	Financial Institution Scrutiny on Climate Risk	June, 2019	State Street Global Advisors	Rakhi Kumar, Michael Younis	Climate-Related Disclosures in Oil and Gas, Mining, and Utilities: The Current State and Opportunities for Improvement
78	Risk Management Guidance	June, 2019	Deloitte Center for Financial Services	n/a	Climate Risk: Regulators Sharpen their Focus
79	Risk Management Guidance	May, 2019	Task Force on Climate-Related Financial Disclosures	n/a	2019 Status Report
80	News & Financial Reporting Coverage	May, 2019	GreenBiz	Joel Makower	Wall Street, ESG, and the Wild West
81	News & Finanical Reporting Coverage	May, 2019	WLOS	Rob Bradley	Drought & deluge: Extreme weather events increasing across WNC
82	Publications from Peer Utilities	May, 2019	Ameren	n/a	Building a Cleaner Energy Future
83	Financial Institution Scrutiny on Climate Risk	April, 2019	n/a	Sarah Breeden, Executive Director, International Bank Supervisoin	Avoiding the storm: Climate Change and the financial system
84	Financial Institution Scrutiny on Climate Risk	April, 2019	n/a	Hans Hoogervorst, Chair of International Accounting Standards Board (IASB)	Speech to Climate-Related Financial Reporting Conference
85	Technical Climate Risk Analysis	April, 2019	BlackRock	Andre Bertolotti, Debarshi Basu, Kenza Akallal, Brian Deese	Climate Risk in the US Electric Utility Sector: A Case Study
86	Technical Climate Risk Analysis	April, 2019	McKinsey & Company	n/a	Why, and How, utilities should start to manage climate-change risk
87	Financial Institution Scrutiny on Climate Risk	April, 2019	Network for Greening the Financial System	n/a	A call for action: Climate change as a source of financial risk

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88	Financial Institution Scrutiny on Climate Risk	April, 2019	Australian Accounting Standards Board	n/a	Climate-related and other emerging risks disclosures: assessing financial statement materiality using AASB/IASB Practice Statement 2
89	Technical Climate Risk Analysis	April, 2019	BlackRock Investment Institute	Brian Deese, Philipp Hildebrand, Rich Kushel, Isabelle Mateos y Lago	Getting Physical: Scenario analysis for assessing climate-related risks
90	Technical Climate Risk Analysis	April, 2019	NARUC	n/a	The Value of Resilience for Distributed Energy Resources: An Overview of Current Analytical Practices.
91	Duke Publications and Statements	March, 2019	Duke Energy	n/a	Annual Shareholder Meeting Proxy Statement
92	Risk Management Guidance	March, 2019	Centre for Policy Development	Noel Hutley	Climate Change and Directors' Duties
93	Publications from Peer Utilities	March, 2019	Xcel	n/a	Building a Carbon-Free Future
94	Technical Climate Risk Analysis	March, 2019	Vibrant Clean Energy, Energy Innovation	Eric Gimon, Mike O'Boyle, Christopher Clack, Sarah McKee	The Coal Cost Crossover: Economic Viability of Existing Coal Compared to New Local Wind and Solar Resources
95	Duke Publications and Statements	February, 2019	Duke Energy	n/a	Form 10-K
96	Financial Institution Scrutiny on Climate Risk	February, 2019	Climate Majority Project	n/a	Institutional Investor Statement Regarding Decarbonization of Electric Utilities
97	News & Financial Reporting Coverage	February, 2019	Reuters	Ross Kerber	Big U.S. pension funds ask electric utilities for decarbonization plans
98	Financial Institution Scrutiny on Climate Risk	February, 2019	Climate Majority Project	n/a	Net-Zero by 2050: Investor risks and opportunities in the context of deep decarbonization of electric generation
99	News & Finanical Reporting Coverage	January, 2019	Wall Street Journal	Russell Gold	PG&E: The First Climate-Change Bankruptcy, Probably Not the Last
100	News & Financial Reporting Coverage	January, 2019	Reuters	Sharon Bernstein, Suzanne Barlyn	Insurance losses for California wildfires top $11.4 billion

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101	Financial Institution Scrutiny on Climate Risk	November, 2018	Moody's Investors Service	n/a	Moody's approach to climate risk
102	Context in North Carolina	October, 2018	n/a	Governor Roy Cooper	Executive Order No. 80
103	Technical Climate Risk Analysis	May, 2018	National Climate Assessment	Craig Zamuda, Daniel Bilello, Gunter Conzelmann, Ellen Mecray, Ann Satasngi, Vincent Tidwell, Brian Walker	Energy Supply, Delivery, and Demand
104	Duke Publications and Statements	March, 2018	Duke Energy	n/a	2017 Climate Report to Shareholders
105	Risk Management Guidance	February, 2018	US Government Accountability Office	n/a	Climate-related Risks: SEC Has Tkaen Steps to Clarify Disclosure Requirements
106	Financial Institution Scrutiny on Climate Risk	November, 2017	Moody's Investors Service	n/a	Evaluating the Impact of Climate Change on US state and local issuers
107	Risk Management Guidance	August, 2017	The Brattle Group	n/a	Compensating Risk in Evolving Utility Business Models
108	Risk Management Guidance	June, 2017	Task Force on Climate-Related Financial Disclosures	n/a	Recommendations of the Task Force
109	Risk Management Guidance	June, 2017	Task Force on Climate-Related Financial Disclosures	n/a	The Use of Scenario Analysis in Disclosure of Cliamte-Related Risks and Opportunities
110	Risk Management Guidance	May, 2017	50/50 Climate Project	n/a	Utility Climate Change Readiness: A Business Plan Analysis
111	Technical Climate Risk Analysis	January, 2017	The Rhodium Group	Kate Laresen, John Larsen, Whitney Herndon, Michael Delgado, Shashank Mohan	Assessing the Effect of Rising Temperatures; The Cost of Climate Change to the US Power Sector
112	Risk Management Guidance	January, 2017	Center for International Environmental Law	n/a	Trillion Dollar Transformation: Fiduciary Duty, Divestment, and Fossil Fuels in an Era of Climate Risk

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113	Risk Management Guidance	September, 2016	US Department of Energy	n/a	Climate Change and the Electricity Sector: Guide for Climate Change Resilience Planning
114	Risk Management Guidance	September, 2016	Columbia Sabin Center for Climate Change Law	Payal Nanavati and Justin Gundlach	Legal Tools for Climate Adaptation Advocacy: The Electric Grid and Its Regulators -- FERC and State Public Utility Commissions
115	Financial Institution Scrutiny on Climate Risk	September, 2016	BlackRock	n/a	Adapting Portfolios to Climate Change
116	Academic Research on Climate Risk	May, 2016	Journal of Business Ethics	Juhyun Jung, Kathleen Herbohn, Peter Clarkson	Carbon Risk, Carbon Risk Awareness, and the Cost of Debt Financing
117	Risk Management Guidance	January, 2016	California Public Utilities Commission	Kristin Ralff-Douglas	Climate Adaptation in the Electric Sector: Vulnerability Assessments & Resilience Plans
118	Publications from Peer Utilities	January, 2016	PG&E	n/a	Climate Change Vulnerability Assessment
119	Financial Institution Scrutiny on Climate Risk	September, 2015	Mark Carney, Governor of the Bank of England, Chairman of the Financial Stability Board	n/a	Breaking the Tragedy of the Horizon--Climate Change and Financial Stability
120	Academic Research on Climate Risk	September, 2015	Energy Economics	John E. Bistline	Electric sector capacity planning under uncertainty: Climate policy and natural gas in the US
121	Academic Research on Climate Risk	June, 2014	n/a	Piere Audinet, Jean-Christophe Amado, Ben Rabb (World Bank)	Climate Risk Management Approaches in the Electricity Sector: Lessons from Early Adapters
122	Academic Research on Climate Risk	June, 2014	Lawrence Berkeley National Lab	Peter Larsen, et al. (Lawrence Berkeley National Laboratory)	Exploring the Reliability of U.S. Electric Utilities
123	Risk Management Guidance	March, 2014	Edison Electric Institute	n/a	Before and After the Storm: A compilation of recent studies, programs, and policies related to storm hardening and resiliency
124	Risk Management Guidance	January, 2014	US Government Accountability Office	n/a	Climate Change: Energy Infrastructure Risks and Adaptation Efforts

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125	Risk Management Guidance	September, 2011	BSR	n/a	Adapting to Climate Change: A Guide for the Energy and Utility Industry
126	Publications from Peer Utilities	January, 2010	Entergy	n/a	Building a Resilient Energy Gulf Coast
127	Duke Publications and Statements	2020	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2019
128	Duke Publications and Statements	2019	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2018
129	Publications from Peer Utilities	2019	SCE	n/a	Form 10-K
130	Publications from Peer Utilities	2019	Xcel	n/a	Form 10-K
131	Duke Publications and Statements	2018	CDP	n/a	Duke Energy Response to Climate Change Questionnaire, 2017

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EXHIBIT JMV-TF-6: COMPARISON OF CLIMATE RISK ASSESSMENT

Introduction

This appendix conducts a more in-depth review of Duke Energy Carolinas' assessment of and responses to climate-related risks in its Grid Improvement Plan. We use the Con Edison ("ConEd") Climate Change Vulnerability Study, released in December 2019, as an exemplar, and pull in materials from the Company's application and discovery responses to characterize the Company's assessment and response.

Although the collaborative process and resulting vulnerability study serve as a "nationwide model" for resiliency planning,[1] ConEd benefitted from several unique factors that enabled it to pursue such a comprehensive approach. The Storm Hardening & Resiliency Collaborative was convened after Hurricane Sandy in 2014, at the recommendation of Commission staff, and the Collaborative honed an approach for this study over 5 years. Further, the Company had express approval for costs recovery of any climate risk vulnerability assessment projects undergone at the recommendation of the Collaborative. The increased certainty of approval and recovery may have contributed to the comprehensive, 36-month process that led to the Vulnerability Study.[2] In total, the Study estimates that climate vulnerabilities could cost ConEd up between $1.3 and $4.6 billion by 2050.[3]

The purpose of this comparison is to demonstrate, through comparison, the level of depth and analytical persuasion the ConEd vulnerability study was able to pursue through collaboration and regulatory support, and show the value that such a comprehensive climate risk approach could have to grid modernization in this proceeding. Beyond analytical complexity, the Study also demonstrates a patient and expansive approach by starting with information gathering, embracing

[1] Ralff-Douglas, K., (2016, September). Climate Adaptation in the Electricity Sector: Vulnerability Assessments & Resiliency Plans. *California Public Utilities Commission,* p. 5. Retrieved at: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/About_Us/Organization/Divisions/Policy_and_Planning/PPD_Work/PPD_Work_Products_(2014_forward)/PPD%20-%20Climate%20Adaptation%20Plans.pdf.

[2] ConEd, (2015, September). Storm Hardening and Resiliency Collaborative Phase Three Report ("Phase Three Report"). New York Public Service Commission Case 13-E-0030.

[3] Consolidated Edison Company of New York Inc. ("ConEd"), (2019, December). Climate Change Vulnerability Study ("ConEd Climate Study"). P. 4. Retrieved at https://www.coned.com/-/media/files/coned/documents/our-energy-future/our-energy-projects/climate-change-resiliency-plan/climate-change-vulnerability-study.pdf.

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an iterative process, and including a broader set of resiliency solutions into the study, including customer-centered solutions.

In 2018, the Duke Energy Corporation published a Climate Report to Shareholders, which discusses climate-related risks at a high level and their relation to the Corporation's general strategy.[4] In correspondence, the Company indicated that the report "speaks for itself, is intended 'To provide information on Duke Energy's strategy and the steps [it] is taking to mitigate risks from climate change,'" and "Does not, and was not intended to, identify actual or potential costs for which recovery is sought in this proceeding."[5] Based on this representation, this appendix will not consider the Report to Shareholders as an analysis of climate-related risks of the Company's assets or operations.

Finally, It is also worth noting that the Company finds that helping to prevent climate change is in the public interest.[6] Presumably, this finding of public interest would extend to limiting the effects of climate change on the Company's provision of affordable rates and reliable service.

The comparison is conducted in the table below. Practices from the ConEd Vulnerability Study populate the left side of the table; practices shown by the Company will be demonstrated on the right side.

[4] Duke Energy Corporation (2018, March). 2017 Climate Report to Shareholders. Retrieved at https://www.duke-energy.com/_/media/pdfs/our-company/shareholder-climate-report.pdf.
[5] Company Response to Vote Solar Data Request 1-3, *via* Company Response to Vote Solar Data Request 1 Supplemental – 2.
[6] Duke Energy Carolinas, LLC ("Company") Response to Center for Biological Diversity & Appalachian Voices ("CBD&AV") Data Request 2-34.

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General		
Category	**ConEd Vulnerability Study**	**Duke Energy Carolinas Grid Improvement Plan (GIP)**
Acknowledgment of Climate-Related Risks	"Con Edison recognizes the global scientific consensus that climate change is occurring at an accelerating rate."[7] One of the purposes of the Vulnerability Study is to "develop a shared understanding of… projected climate and extreme weather for the territory."[8]	Company is "without knowledge" as to the role of climate change in relation to major storm events.[9] GIP includes "Impact of Weather Events" and "Environmental Policy" as "megatrends" but declines to confirm their relation to climate-related risks.[10]
Treatment of Uncertainty	"The exact timing and magnitude of future climate change is uncertain. To account for climate uncertainty, the Study considered a range of potential climate futures …"[11]	"It is the Company's position that the Grid Improvement Plan is designed to deal with facts as known today and reasonable predictions of future events. The Company as well as its stakeholders, are unable to say with certainty what the future impacts of climate change may or may not be."[12]
Role of Stakeholders	Climate Change Vulnerability Study emerged from a co-operative proceeding facilitated by ConEd.[13]	The Company declined discussion of climate-related risks with stakeholders,[14] despite specific requests.[15]
Climate Science	ConEd used "best available climate science," to construct an in-house,	Megatrends documentation uses a combination of news articles and

[7] ConEd Climate Study, p.4.
[8] *Ibid.* p. 11.
[9] Company Response to Vote Solar Data Request 1 Supplemental – 3.
[10] Company Response to Vote Solar Data Request 3-24.
[11] ConEd Climate Study, p. 4.
[12] Company Response to Vote Solar ("VS")Data Request 3-24.
[13] ConEd, (2015, September). Storm Hardening and Resiliency Collaborative Phase Three Report ("Phase Three Report"). New York Public Service Commission Case 13-E-0030.
[14] Direct Testimony of Company Witness Jay W. Oliver ("Oliver Direct"), Exhibit 13, page 25.
[15] *Ibid.,* Ex. 13, p. 29.

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	downscaled climate model[16] and ultimately "synthesized information into metrics relating plausible effects of climate changes on operations, infrastructure, and planning."[17]	historical metrics.[18] "Implications" use a qualitative, red-yellow-green approach (See Figure 1 below).[19]
Forward-looking Analysis	Study team used a risk-based approach taking into account both likelihood and consequences of climate impacts.[20]	No forward-looking climate-related analysis propounded in application materials.
Forward-looking Strategy	Study uses an 'adaptation pathways' approach that anticipates future changes and plans a sequence of interventions.[21]	The Company "has not developed any future phases of the plan,"[22] although some potential phase two projects have been described.[23]
Solutions Selection Process	ConEdison conducted a systematic, forward-looking, asset-level risk analysis before identifying adaptation options.[24]	Company identified tools available after a high-level, qualitative review of Megatrends implications.[25]
Cost-benefit Analysis	ConEd uses a systematic benefit cost analysis (CBA) handbook, developed as a part of its distributed systems implementation plan.[26] BCA incorporates social costs and is used as a criteria in solution selection.	Company did not demonstrate a cost-benefit analysis until the Plan's investments were identified

[16] ConEd Cliate Study, p. 18.
[17] ConEd Climate Study, p. 12.
[18] Oliver Direct, Ex. 2, p. 11.
[19] Oliver Direct, Ex. 3, p. 10.
[20] ConEd Climate Study, p. 12.
[21] *Ibid*. p. 12.
[22] Company Response to Tech Customers Data Request 6-5.
[23] Oliver Direct, p. 50-51.
[24] ConEd Climate Study, p. 14-15.
[25] Oliver Direct, p. 32, ll. 19 to p. 33, ll. 2.
[26] ConEd Cliamte Study, p. 64.

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Customer Resilience Options	ConEd integrates climate resilience options for ratepayers, such as resilience hubs and DERs, into their own planning.[27]	Company did not consider customer-oriented or non-wires alternatives to address Megatrends.[28]
Sizing Investment Response	Solutions are optimized to minimize costs between societal cost of an outage and expected cost of intervention (see Figure 2, below).[29]	Company appears to not have considered different scales of Grid Improvement Plan.[30]
Specific Risks		
Temperature, Heat Index , and Heat Waves	**Worker Safety:** High heat risk days will grow from 2 days per year in historical period to 5-7 days per year by 2050 and 14-20 days per year by 2100. **Load:** Independent of other drivers, load will increase. Costs of serving incremental peak are between $1.1 and $3.1 billion by 2050.[31] **Asset Deterioration:** Higher heat stress will lead to increased deterioration, transmission line sagging, and decreased asset capacity. ConEd's incomplete estimate of the cost of deterioration is $237 to $510 million by 2050.[32]	**Worker Safety:** To our knowledge, the Company has not quantified increased worker safety risk due to heat. **Load:** The Company does not use forward-looking climate impact projection in load forecasts.[33] **Asset Deterioration:** The Company has not integrated shifts in temperature into asset deterioration. It is not clear if the Company believes that such risks are material.[34]

[27] ConEd Climate Study, p. 36.
[28] Company Response to Vote Solar Data Request 3-17.
[29] ConEd Climate Study, p.62.
[30] Company Response to Tech Customers Data Request 6-8.
[31] ConEd Study, p. 42.
[32] ConEd Study, p. 40-41.
[33] Company Response to Vote Solar Data Requests 1-20 and 1-21.
[34] Company Response to Vote Solar Data Requests 5-5 through 5-9.

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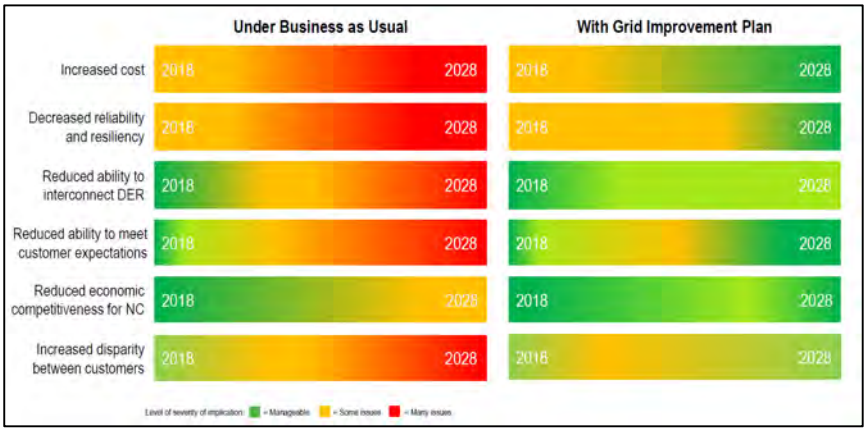
Flooding	ConEd found that sea level could exceed its current design standard (100-year floodplain plus 3 feet) between 2030 and 2080. Hardening all at-risk substations in the worst-case scenario would cost $636 million.	The Company has conducted flood risk analysis of transmission sub-stations for substations that have been flooded recently. Upgraded sub-stations will be built at a 500-year FEMA floodplain plus 1 foot (in the cases studied, this represented 0 to 1 feet higher than ConEd's 100-year plus 3 standard). No forward-looking flood risk projection was conducted.[35]
Precipitation & Extreme Weather	ConEdison described these risks qualitatively, but found assets would be more at risk due to climate change. "On an operational level, increasing frequency and intensity of extreme weather events may exceed Con Edison's currently robust emergency preparedness efforts."[36]	The Company does not factor climate change into the consideration of the frequency of major events or in determining the budget amount.[37]

Figure 1: Company's Presentation of Grid Improvement Plan Risks[38]



[35] Company Response to Vote Solar Data Request 3-23.
[36] ConEd Climate Study, p. 33.
[37] Company Response to CBD&AV Data Request 2-33.
[38] Image retrieved directly from Oliver Direct Ex. 3, p. 10.

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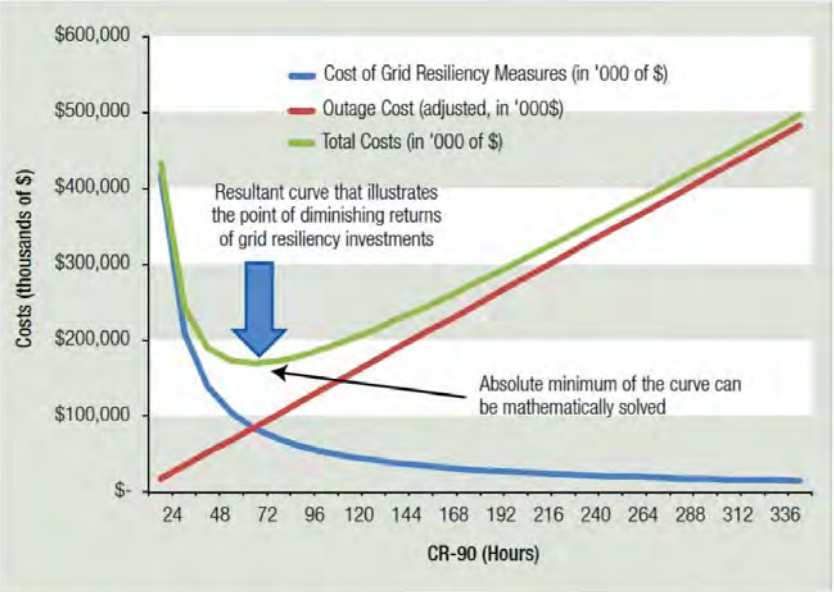
Figure 2: Optimizing Costs of Resilience Interventions[39]



The graph above shows the total cost of investing in resiliency to outages, split between the social costs of the outage and the cost of investing in grid resiliency. CR-90 along the x-axis represents the time taken to restore power to 90% of ratepayers. The y-axis represents social costs.

Conclusion and Discussion

Clearly, ConEd and Duke Energy Carolinas' approaches to climate risk assessment differ at a fundamental level. ConEd's approach begins with a basic acknowledgment of the need to plan around climate risks; it gathers as much information as possible from specific climate science, stakeholders, and internal subject matter experts; then, it clearly articulates the current and future risks that face specific assets and operations, quantifying where possible. Although the full resilience plan will be published in December 2020 with the ConEd Climate Implementation plan, there are glimpses of ConEd's general bearing here: ConEd collaborated with stakeholders on its methodology for evaluating resilience solutions, and its path forward is flexible and iterative.

Duke Energy Carolinas' approach differs in key ways. The depth of information gathering, analysis and stakeholder integration in vulnerability assessment is much less robust, and as a result current and future risks to specific assets and operations are not available. Partly as a result of the

[39] Image taken directly from ConEd Study, p. 63.

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lack of an analytically robust baseline, the Company did not execute an open or transparent solution selection process, and its forward implementation strategy is unclear.

The ConEd study's careful assessment of climate-related impacts on extreme weather events puts into relief the much less robust connection between Duke Energy Carolinas' articulated need to respond to 'increasing' weather events[40] and the Company's lack of any explicit climate-informed risk assessment in this proceeding. The Company's acknowledgement that it did not consider future flood risks,[41] despite the explicit flood hardening purpose of at least one Grid Improvement Plan project,[42] exemplifies this disconnect.

[40] Direct Testimony of Company Witness Stephen G. Demay ("DeMay Direct"), p. 6, ll. 8 and Oliver Direct, p. 29, ll. 4.
[41] See *Supra* note 35.
[42] Oliver Direct, Ex. 10, p. 22.

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Docket No. E-7, Sub 1214

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State of North Carolina

ROY COOPER
GOVERNOR

October 29, 2018

EXECUTIVE ORDER NO. 80

NORTH CAROLINA'S COMMITMENT TO ADDRESS CLIMATE CHANGE AND TRANSITION TO A CLEAN ENERGY ECONOMY

WHEREAS, North Carolina residents deserve to be better educated, healthier, and more financially secure so that they may live purposeful and abundant lives; and

WHEREAS, N.C. Const. art. XIV, § 5 requires the conservation, protection, and preservation of state lands and waters in public trust; and

WHEREAS, North Carolina is well positioned to take advantage of its technology and research and development sectors, along with its skilled workforce, to promote clean energy technology solutions and a modernized electric grid; and

WHEREAS, public-private partnerships in North Carolina foster market innovations and develop clean energy technology solutions that grow the state's economy; and

WHEREAS, the effects of more frequent and intense hurricanes, flooding, extreme temperatures, droughts, saltwater intrusion, and beach erosion have already impacted and will continue to impact North Carolina's economy; and

WHEREAS, climate-related environmental disruptions pose significant health risks to North Carolinians, including waterborne disease outbreaks, compromised drinking water, increases in disease-spreading organisms, and exposure to air pollution, among other issues; and

WHEREAS, to maintain economic growth and development and to provide responsible environmental stewardship, we must build resilient communities and develop strategies to mitigate and prepare for climate-related impacts in North Carolina.

NOW, THEREFORE, by the authority vested in me as Governor by the Constitution and the laws of the State of North Carolina, **IT IS ORDERED**:

1. The State of North Carolina will support the 2015 Paris Agreement goals and honor the state's commitments to the United States Climate Alliance.

   The State of North Carolina will strive to accomplish the following by 2025:

   a. Reduce statewide greenhouse gas emissions to 40% below 2005 levels;
   b. Increase the number of registered, zero-emission vehicles ("ZEVs"; individually, "ZEV") to at least 80,000;
   c. Reduce energy consumption per square foot in state-owned buildings by at least 40% from fiscal year 2002-2003 levels.

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2. Cabinet agencies shall evaluate the impacts of climate change on their programs and operations and integrate climate change mitigation and adaptation practices into their programs and operations. Council of State members, higher education institutions, local governments, private businesses, and other North Carolina entities are encouraged to address climate change and provide input on climate change mitigation and adaptation measures developed through the implementation of this Executive Order. Consistent with applicable law, cabinet agencies shall actively support such actions.

3. The Secretary or designee of each cabinet agency and a representative from the Governor's Office shall serve on the North Carolina Climate Change Interagency Council ("Council"), which is hereby established. The Secretary of the North Carolina Department of Environmental Quality, or the Secretary's designee, shall serve as the Council Chair. The North Carolina Department of Environmental Quality shall lead the Council by providing strategic direction, scheduling and planning Council meetings, determining the prioritization of activities, facilitating stakeholder engagement, and assisting in the implementation of pathways to achieve the goals provided in Section 1 of this Executive Order.

   The duties of the Council shall include the following:

   a. Recommend new and updated goals and actions to meaningfully address climate change;
   b. Develop, implement, and evaluate programs and activities that support statewide climate mitigation and adaptation practices;
   c. Establish workgroups, as appropriate, to assist the Council in its duties;
   d. Consider stakeholder input when developing recommendations, programs, and other actions and activities;
   e. Schedule, monitor, and provide input on the preparation and development of the plans and assessments required by this Executive Order;
   f. Review and submit to the Governor the plans and assessments required by this Executive Order.

4. The North Carolina Department of Environmental Quality ("DEQ") shall develop a North Carolina Clean Energy Plan ("Clean Energy Plan") that fosters and encourages the utilization of clean energy resources, including energy efficiency, solar, wind, energy storage, and other innovative technologies in the public and private sectors, and the integration of those resources to facilitate the development of a modern and resilient electric grid. DEQ shall collaborate with businesses, industries, power providers, technology developers, North Carolina residents, local governments, and other interested stakeholders to increase the utilization of clean energy technologies, energy efficiency measures, and clean transportation solutions. DEQ shall complete the Clean Energy Plan for the Council to submit to the Governor by October 1, 2019.

5. The North Carolina Department of Transportation ("DOT"), in coordination with DEQ, shall develop a North Carolina ZEV Plan ("ZEV Plan") designed to increase the number of registered ZEVs in the state to at least 80,000 by 2025. The ZEV Plan shall help establish interstate and intrastate ZEV corridors, coordinate and increase the installation of ZEV infrastructure, and incorporate, where appropriate, additional best practices for increasing ZEV adoption. DOT shall complete the ZEV Plan for the Council to submit to the Governor by October 1, 2019.

6. The North Carolina Department of Commerce ("DOC") and other cabinet agencies shall take actions supporting the expansion of clean energy businesses and service providers, clean technology investment, and companies with a commitment to procuring renewable energy. In addition, DOC shall develop clean energy and clean transportation workforce assessments for the Council to submit to the Governor by October 1, 2019. These assessments shall evaluate the current and projected workforce demands in North Carolina's clean energy and clean transportation sectors, assess the skills and education required for employment in those sectors, and recommend actions to help North Carolinians develop such skills and education.

7. Cabinet agencies shall prioritize ZEVs in the purchase or lease of new vehicles and shall use ZEVs for agency business travel when feasible. When ZEV use is not feasible, cabinet agencies shall prioritize cost-effective, low-emission alternatives. To support implementation of this directive, the North Carolina Department of Administration ("DOA") shall develop a North

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Carolina Motor Fleet ZEV Plan ("Motor Fleet ZEV Plan") that identifies the types of trips for which a ZEV is feasible, recommends infrastructure necessary to support ZEV use, develops procurement options and strategies to increase the purchase and utilization of ZEVs, and addresses other key topics. DOA shall complete the Motor Fleet ZEV Plan and provide an accounting of each agency's ZEVs and miles driven by vehicle type for the Council to submit to the Governor by October 1, 2019, and annually thereafter.

8. Building on the energy, water, and utility use conservation measures taken pursuant to N.C. Gen. Stat. § 143-64.12(a), DEQ shall update and amend, where applicable, a Comprehensive Energy, Water, and Utility Use Conservation Program ("Comprehensive Program") by February 1, 2019, and biennially beginning December 1, 2019, to further reduce energy consumption per gross square foot in state buildings consistent with Section 1 of this Executive Order. The Comprehensive Program shall include best practices for state government building energy efficiency, training for agency staff, cost estimation methodologies, financing options, and reporting requirements for cabinet agencies. DEQ and cabinet agencies shall encourage and assist, as requested, higher education institutions, K-12 schools, and local governments in reducing energy consumption. To achieve the required energy consumption reductions:

    a. By January 15, 2019, each cabinet agency shall designate an Agency Energy Manager, who shall serve as the agency point of contact.
    b. Each cabinet agency shall develop and submit an Agency Utility Management Plan to DEQ by March 1, 2019, and biennially thereafter, and implement strategies to support the energy consumption reduction goal set forth in Section 1 of this Executive Order. DEQ shall assess the adequacy of these plans and their compliance with this Executive Order.
    c. By September 1, 2019, and annually thereafter, each cabinet agency shall submit to DEQ an Agency Utility Report detailing its utility consumption, utility costs, and progress in reducing energy consumption.
    d. DEQ shall develop an annual report that describes the Comprehensive Program and summarizes each cabinet agency's utility consumption, utility costs, and achieved reductions in energy consumption. DEQ shall complete this report for publication on its website and for the Council to submit to the Governor by February 1, 2019, and annually thereafter beginning December 1, 2019.

9. Cabinet agencies shall integrate climate adaptation and resiliency planning into their policies, programs, and operations (i) to support communities and sectors of the economy that are vulnerable to the effects of climate change and (ii) to enhance the agencies' ability to protect human life and health, property, natural and built infrastructure, cultural resources, and other public and private assets of value to North Carolinians.

    a. DEQ, with the support of cabinet agencies and informed by stakeholder engagement, shall prepare a North Carolina Climate Risk Assessment and Resiliency Plan for the Council to submit to the Governor by March 1, 2020.
    b. The Council shall support communities that are interested in assessing risks and vulnerabilities to natural and built infrastructure and in developing community-level adaptation and resiliency plans.

10. DEQ shall prepare and manage a publicly accessible Web-based portal detailing the Council's actions and the steps taken to address climate-related impacts in North Carolina. Cabinet agencies shall submit data, information, and status reports as specified by the Council to be published on the portal. In addition, DEQ shall develop, publish on the portal, and periodically update an inventory of the state's greenhouse gas emissions that, among other things, tracks emissions trends statewide by sector and identifies opportunities for additional emissions reductions.

11. By October 15, 2019, and annually thereafter, the Council shall provide to the Governor a status report on the implementation of this Executive Order.

12. This Executive Order is consistent with and does not otherwise abrogate existing state law.

13. This Order is effective October 29, 2018 and shall remain in effect until rescinded or superseded by another applicable Executive Order.

IN WITNESS WHEREOF, I have hereunto signed my name and affixed the Great Seal of the State of North Carolina at the Capitol in the City of Raleigh, this the 29th day of October, in the year of our Lord two thousand eighteen.

Roy Cooper
Governor

ATTEST:

Rodney S. Maddox
Chief Deputy Secretary of State

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Feb 18 2020

Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 43

Docket No. E-7, Sub 1214

Date of Request: **October 16, 2019**
Date of Response: **November 6, 2019**

[X] **CONFIDENTIAL**

[ ] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to North Carolina Public Staff Data Request No. 43-19, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 43
DEC Docket No. E-7, Sub 1214
Item No. 43-19
Page 1 of 1

Feb 18 2020

Request:

19. Direct Testimony of John S. Spanos, page 15, lines 6-15, discusses decommissioning studies. Please provide the decommissioning studies referenced.

Confidential Response:

[redacted]

[redacted]

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Exhibit 2

Pages 3 - 121

Redacted as

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Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 43

Docket No. E-7, Sub 1214

Date of Request: **October 16, 2019**
Date of Response: **October 28, 2019**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to North Carolina Public Staff Data Request No. 43-17, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 43
DEC Docket No. E-7, Sub 1214
Item No. 43-17
Page 1 of 1

Request:

17. Regarding pages VIII-4 – VIII-5 of Spanos Exhibit 1 (2018 Depreciation Study).
a. Please provide the workpaper that supports the "Total Decommissioning Costs" shown on column (5).
b. For what year are the dollar amounts shown in column (5)?
c. Please provide the formula used to calculate the "Escalated Total Decommissioning Costs" shown in column (6).
d. Please provide support for the escalation factor used to calculate the amounts shown in column (6).
e. Please provide the workpapers that support the "Terminal Retirement" amounts shown in column (7).
f. Please provide these workpapers requested in parts (a)-(e) electronically in Excel (or text delimited format if not available in Excel). If not available electronically, please provide a hard copy.

Response:

a. See attachments provided in response to PS DR 1-8. The requested information has been provided in electronic format in the referenced attachments.

b. The decommissioning studies are based on current cost to retire the facilities in 2016 dollars.

c. The formula to calculate the Escalated Total Decommissioning Costs is:
= Total Decommission Costs * (1.025^(Estimated Retirement Year – 2016)

d. The 2.5% escalation rate is supported by recent CPI data series, which are available at www.bls.gov, and long term CPI forecasts, which are available from the Federal Reserve Bank of Philadelphia's Livingston Survey at https://www.philadelphiafed.org/research-and-data/real-time-center/livingston-survey

e. See attachments provided in response to PS DR 1-8. The requested information has been provided in electronic format in the referenced attachments.

f. Please refer to the responses to parts a.) – e.).

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DUKE ENERGY® CAROLINAS

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2018

Prepared by:

Gannett Fleming

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DUKE ENERGY CAROLINAS

TABLE 3. CALCULATION OF TERMINAL NET SALVAGE PERCENT

UNIT	ESTIMATED RETIREMENT YEAR	TOTAL DECOMMISSIONING COSTS	ESCALATED TOTAL DECOMMISSIONING COSTS	TERMINAL RETIREMENTS	TOTAL NET SALVAGE
(1)	(2)	(5)	(6)	(7)	(8)
STEAM PRODUCTION					
MARSHALL	2034	41,562,000	64,822,536	(1,570,213,838)	(4)
BELEWS CREEK	2037	62,677,000	105,271,152	(1,929,524,339)	(5)
CLIFFSIDE (J. E. ROGERS)	2048	48,075,000	105,945,615	(2,534,075,610)	(4)
LEE	2030	7,342,000	10,374,054	(101,083,692)	(10)
ALLEN	2024	40,102,000	48,860,393	(1,197,904,245)	(4)
TOTAL STEAM PRODUCTION		**199,758,000**	**335,273,750**	**(7,332,801,723)**	**(5)**
HYDRO PRODUCTION					
COWANS FORD	2055	2,623,000	6,871,144	(85,913,580)	(8)
BAD CREEK	2058	1,138,000	3,210,293	(746,661,723)	(0)
JOCASSEE	2046	424,000	889,369	(138,577,695)	(1)
KEOWEE	2046	1,260,000	2,642,935	(109,116,348)	(2)
FISHING CREEK	2055	2,129,000	5,577,074	(35,872,864)	(16)
CEDAR CREEK	2055	1,435,000	3,759,089	(25,063,845)	(15)
BRIDGEWATER	2055	1,225,000	3,208,979	(186,507,114)	(2)
GASTON SHOALS	2036	1,875,000	3,072,406	(19,039,393)	(16)
LOOKOUT SHOALS	2055	1,384,000	3,625,491	(15,471,872)	(23)
MOUNTAIN ISLAND	2055	1,939,000	5,079,355	(20,429,429)	(25)
99 ISLANDS	2036	2,633,000	4,314,477	(23,320,269)	(19)
OXFORD	2055	1,018,000	2,666,727	(49,267,017)	(5)
RHODHISS	2055	1,465,000	3,837,677	(24,285,075)	(16)
TUXEDO	2041	1,001,000	1,855,798	(9,879,410)	(19)
WATEREE	2055	2,095,000	5,488,009	(39,728,899)	(14)
WYLIE	2055	1,913,000	5,011,246	(38,671,320)	(13)
GREAT FALLS	2055	3,736,000	9,786,730	(6,004,050)	(163)
DEARBORN	2055	1,398,000	3,662,165	(14,160,657)	(26)
NPL BEAR CREEK	2041	593,000	1,099,389	(10,585,822)	(10)
NPL BRYSON	2041	950,000	1,761,247	(6,055,494)	(29)
NPL CEDAR CLIFF	2041	853,000	1,581,414	(6,680,605)	(24)
NPL FRANKLIN	2041	939,000	1,740,854	(7,806,336)	(22)
NPL MISSION	2041	1,430,000	2,651,140	(7,628,114)	(35)
NPL NANTAHALA	2042	881,000	1,674,158	(18,835,346)	(9)
NPL QUEENS CREEK	2032	677,000	1,005,010	(1,197,093)	(84)
NPL TENNESSEE CREEK	2041	706,000	1,308,885	(6,692,287)	(20)
NPL THORPE	2041	850,000	1,575,852	(9,493,786)	(17)
NPL TUCKASEGEE	2041	589,000	1,091,973	(3,228,369)	(34)
TOTAL HYDRO PRODUCTION		**39,159,000**	**90,048,886**	**(1,666,173,814)**	**(5)**

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DUKE ENERGY CAROLINAS

TABLE 3. CALCULATION OF TERMINAL NET SALVAGE PERCENT

UNIT	ESTIMATED RETIREMENT YEAR	TOTAL DECOMMISSIONING COSTS	ESCALATED TOTAL DECOMMISSIONING COSTS	TERMINAL RETIREMENTS	TOTAL NET SALVAGE
(1)	(2)	(5)	(6)	(7)	(8)
OTHER PRODUCTION					
LINCOLN	2035	7,151,000	11,431,947	(290,010,583)	(4)
DAN RIVER CC	2052	8,123,000	19,759,484	(408,016,726)	(5)
LEE	2047	1,000,000	2,150,007	(37,057,744)	(6)
MILL CREEK	2043	3,328,000	6,482,278	(152,640,891)	(4)
ROCKINGHAM	2040	2,385,000	4,313,811	(241,367,037)	(2)
BUCK CC	2051	7,916,000	18,786,292	(410,916,459)	(5)
LEE CC	2058	8,123,000	21,810,774	(315,671,573)	(7)
TOTAL OTHER PRODUCTION		**38,026,000**	**84,734,593**	**(1,855,681,013)**	**(5)**
SOLAR PRODUCTION					
MOCKSVILLE	2041	1,874,000	3,474,291	(16,804,441)	(21)
MONROE	2042	7,301,280	13,536,165	(61,490,037)	(22)
WOODLEAF	2043	730,128	1,353,616	(6,992,829)	(19)
TOTAL SOLAR PRODUCTION		**9,905,408**	**18,364,072**	**(85,287,307)**	**(22)**
TOTAL PRODUCTION		**286,848,408**	**528,421,301**	**(10,939,943,856)**	**(5)**

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Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 76

Docket No. E-7, Sub 1214

Date of Request: **November 13, 2019**
Date of Response: **November 25, 2019**

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The attached response to North Carolina Public Staff Data Request No. 76-1, was provided to me by the following individual(s): Melissa B. Abernathy, Manager, Accounting II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 76
DEC Docket No. E-7, Sub 1214
Item No. 76-1
Page 1 of 1

Request:

1. Please provide the source for the Interim Retirements Net Salvage percent shown in column (5) on page 306 of Spanos Exhibit 1.

Response:

The attached file, PS DR 76-1 Attachment.xlsx, sets forth the interim net salvage percents shown in column (5) on page 306 of Spanos Exhibit 1. The statistical data for interim net salvage is set forth on pages VIII-6 through VIII-28.

PS DR 76-1
Attachment.xlsx

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DUKE ENERGY CAROLINAS

INTERIM NET SALVAGE CALCULATION

ACCOUNT	INTERIM NET SALVAGE %	ESTIMATED FUTURE INTERIM RETIREMENTS	2018 ORIGINAL COST AS A PERCENT OF TOTAL	WEIGHTED AVERAGE OF INTERIM NET SALVAGE (%)
(1)	(2)	(3)	(4)	(5)=(2)*(4)
STEAM PRODUCTION				
311.00	(20)	29,863,904.71	3.21%	(1)
312.00	(15)	671,298,499.48	72.26%	(11)
314.00	(5)	122,806,874.05	13.22%	(1)
315.00	(10)	52,917,661.51	5.70%	(1)
316.00	(5)	52,054,802.57	5.60%	0
TOTAL STEAM PRODUCTION		**928,941,742.32**		**(14)**
NUCLEAR PRODUCTION				
321.00	(10)	444,050,814.81	23.05%	(2)
322.00	(10)	925,017,581.78	48.02%	(5)
323.00	(5)	240,354,197.67	12.48%	(1)
324.00	(10)	191,068,030.22	9.92%	(1)
325.00	(2)	125,959,406.99	6.54%	0
TOTAL NUCLEAR PRODUCTION		**1,926,450,031.47**		**(9)**
HYDRO PRODUCTION				
331.00	(25)	108,818,076.77	23.31%	(6)
332.00	(25)	99,982,006.61	21.42%	(5)
333.00	(25)	181,259,912.05	38.83%	(10)
334.00	(5)	48,030,474.78	10.29%	(1)
335.00	(5)	23,147,643.56	4.96%	0
336.00	0	5,546,737.98	1.19%	0
TOTAL HYDRO PRODUCTION		**466,784,851.75**		**(22)**
OTHER PRODUCTION				
341.00	(10)	92,418,725.63	9.87%	(1)
342.00	(5)	22,429,792.45	2.40%	0
343.00	(5)	493,587,104.19	52.72%	(3)
344.00	(5)	196,741,192.40	21.01%	(1)
345.00	(5)	115,775,982.39	12.37%	(1)
346.00	(5)	15,327,224.65	1.64%	0
TOTAL OTHER PRODUCTION		**936,280,021.71**		**(6)**

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DUKE ENERGY® CAROLINAS

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO ELECTRIC PLANT AS OF DECEMBER 31, 2018

Prepared by:

Gannett Fleming

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DUKE ENERGY CAROLINAS

ACCOUNT 342 FUEL HOLDERS, PRODUCERS AND ACCESSORIES

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2007		73,462-				73,462	
2008	678,087	28,935-	4-		0	28,935	4
2009				33,774		33,774	
2010							
2011							
2012	393,409		0		0		0
2013							
2014	152,372		0		0		0
2015	665,472	54,162	8		0	54,162-	8-
2016	208,513	9,542	5	210,080	101	200,538	96
2017	60,785	6,802	11	47,363	78	40,561	67
2018	1,073,616	7,000	1		0	7,000-	1-
TOTAL	3,232,253	24,891-	1-	291,217	9	316,108	10
THREE-YEAR MOVING AVERAGES							
07-09	226,029	34,132-	15-	11,258	5	45,390	20
08-10	226,029	9,645-	4-	11,258	5	20,903	9
09-11				11,258		11,258	
10-12	131,136		0		0		0
11-13	131,136		0		0		0
12-14	181,927		0		0		0
13-15	272,615	18,054	7		0	18,054-	7-
14-16	342,119	21,235	6	70,027	20	48,792	14
15-17	311,590	23,502	8	85,814	28	62,313	20
16-18	447,638	7,781	2	85,814	19	78,033	17
FIVE-YEAR AVERAGE							
14-18	432,151	15,501	4	51,489	12	35,988	8

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DUKE ENERGY CAROLINAS

ACCOUNT 343 PRIME MOVERS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	303,883	467,376	154		0	467,376-	154-
2004							
2005							
2006							
2007		906,796-				906,796	
2008	6,438,583	357,167-	6-		0	357,167	6
2009				549,189		549,189	
2010		611,605		6,332,053		5,720,448	
2011	597,868		0		0		0
2012	14,857,157		0		0		0
2013	7,877,527		0		0		0
2014	11,876,939	466,433	4	13,833,621	116	13,367,188	113
2015	8,818,791	593,326	7	1,744,232	20	1,150,906	13
2016	17,918,917	3,313,256	18	16,870,580	94	13,557,324	76
2017	4,455,159	399,399	9		0	399,399-	9-
2018	20,877,944	115,891	1		0	115,891-	1-
TOTAL	94,022,767	4,703,322	5	39,329,674	42	34,626,352	37
THREE-YEAR MOVING AVERAGES							
03-05	101,294	155,792	154		0	155,792-	154-
04-06							
05-07		302,265-				302,265	
06-08	2,146,194	421,321-	20-		0	421,321	20
07-09	2,146,194	421,321-	20-	183,063	9	604,384	28
08-10	2,146,194	84,813	4	2,293,747	107	2,208,935	103
09-11	199,289	203,868	102	2,293,747		2,089,879	
10-12	5,151,675	203,868	4	2,110,684	41	1,906,816	37
11-13	7,777,517		0		0		0
12-14	11,537,208	155,478	1	4,611,207	40	4,455,729	39
13-15	9,524,419	353,253	4	5,192,617	55	4,839,365	51
14-16	12,871,549	1,457,672	11	10,816,144	84	9,358,473	73
15-17	10,397,622	1,435,327	14	6,204,937	60	4,769,610	46
16-18	14,417,340	1,276,182	9	5,623,527	39	4,347,345	30
FIVE-YEAR AVERAGE							
14-18	12,789,550	977,661	8	6,489,686	51	5,512,026	43

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DUKE ENERGY CAROLINAS

ACCOUNT 344 GENERATORS

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	26,297	40,445	154		0	40,445-	154-
2004	4,554		0		0		0
2005	5,003		0		0		0
2006							
2007		1,267,624-				1,267,624	
2008	9,000,593	499,289-	6-		0	499,289	6
2009	2,678,372		0	444,778	17	444,778	17
2010	6,286,291		0		0		0
2011	336,428	111,700-	33-		0	111,700	33
2012	18,330,397	356,039	2	4,927,912	27	4,571,873	25
2013							
2014	9,019,434	861,572	10	5,207,622	58	4,346,050	48
2015	9,362,321	2,104	0		0	2,104-	0
2016	513,557	300,437	59	6,517,421		6,216,985	
2017	1,939,795	163,125	8	500-	0	163,625-	8-
2018	1,963,618	34,916	2		0	34,916-	2-
TOTAL	59,466,661	119,975-	0	17,097,233	29	17,217,208	29
THREE-YEAR MOVING AVERAGES							
03-05	11,951	13,482	113		0	13,482-	113-
04-06	3,186		0		0		0
05-07	1,668	422,541-			0	422,541	
06-08	3,000,198	588,971-	20-		0	588,971	20
07-09	3,892,988	588,971-	15-	148,259	4	737,230	19
08-10	5,988,419	166,430-	3-	148,259	2	314,689	5
09-11	3,100,364	37,233-	1-	148,259	5	185,493	6
10-12	8,317,705	81,446	1	1,642,637	20	1,561,191	19
11-13	6,222,275	81,446	1	1,642,637	26	1,561,191	25
12-14	9,116,610	405,870	4	3,378,511	37	2,972,641	33
13-15	6,127,252	287,892	5	1,735,874	28	1,447,982	24
14-16	6,298,438	388,038	6	3,908,348	62	3,520,310	56
15-17	3,938,558	155,222	4	2,172,307	55	2,017,085	51
16-18	1,472,323	166,159	11	2,172,307	148	2,006,148	136
FIVE-YEAR AVERAGE							
14-18	4,559,745	272,431	6	2,344,909	51	2,072,478	45

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DUKE ENERGY CAROLINAS

ACCOUNT 345 ACCESSORY ELECTRIC EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2007		146,770-				146,770	
2008	2,257,924	57,809-	3-		0	57,809	3
2009	107,677		0	48,613	45	48,613	45
2010		4,681				4,681-	
2011							
2012	122,634		0		0		0
2013	212,986		0		0		0
2014	510,919	12,915	3		0	12,915-	3-
2015	1,421,152	38,487	3		0	38,487-	3-
2016	2,210,573	30,297	1		0	30,297-	1-
2017	801,854	51,789	6		0	51,789-	6-
2018	1,096,403		0		0		0
TOTAL	8,742,122	66,410-	1-	48,613	1	115,023	1
THREE-YEAR MOVING AVERAGES							
07-09	788,534	68,193-	9-	16,204	2	84,397	11
08-10	788,534	17,709-	2-	16,204	2	33,914	4
09-11	35,892	1,560	4	16,204	45	14,644	41
10-12	40,878	1,560	4		0	1,560-	4-
11-13	111,873		0		0		0
12-14	282,180	4,305	2		0	4,305-	2-
13-15	715,019	17,134	2		0	17,134-	2-
14-16	1,380,881	27,233	2		0	27,233-	2-
15-17	1,477,860	40,191	3		0	40,191-	3-
16-18	1,369,610	27,362	2		0	27,362-	2-
FIVE-YEAR AVERAGE							
14-18	1,208,180	26,698	2		0	26,698-	2-

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DUKE ENERGY CAROLINAS

ACCOUNT 346 MISCELLANEOUS POWER PLANT EQUIPMENT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	111,503		0		0		0
2004	18,347		0		0		0
2005							
2006							
2007							
2008	27,500		0		0		0
2009				6,448		6,448	
2010		1,422				1,422-	
2011							
2012	83,880		0		0		0
2013							
2014		2,948				2,948-	
2015							
2016	121,349	20,448	17		0	20,448-	17-
2017	411,515	129	0		0	129-	0
2018	75,857	586	1		0	586-	1-
TOTAL	849,951	25,533	3	6,448	1	19,084-	2-
THREE-YEAR MOVING AVERAGES							
03-05	43,283		0		0		0
04-06	6,116		0		0		0
05-07							
06-08	9,167		0		0		0
07-09	9,167		0	2,149	23	2,149	23
08-10	9,167	474	5	2,149	23	1,675	18
09-11		474		2,149		1,675	
10-12	27,960	474	2		0	474-	2-
11-13	27,960		0		0		0
12-14	27,960	982	4		0	982-	4-
13-15		982				982-	
14-16	40,450	7,798	19		0	7,798-	19-
15-17	177,621	6,859	4		0	6,859-	4-
16-18	202,907	7,054	3		0	7,054-	3-
FIVE-YEAR AVERAGE							
14-18	121,744	4,822	4		0	4,822-	4-

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Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 43

Docket No. E-7, Sub 1214

Date of Request: **October 16, 2019**
Date of Response: **October 28, 2019**

[X] **CONFIDENTIAL**

[ ] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to North Carolina Public Staff Data Request No. 43-12, was provided to me by the following individual(s): Melissa B. Abernathy, Manager, Accounting II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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North Carolina Public Staff
Data Request No. 43
DEC Docket No. E-7, Sub 1214
Item No. 43-12
Page 1 of 1

Request:

12. Page IX of Spanos Exhibit 1 (2018 Depreciation Study) shows the detailed depreciation calculation for Account 370.02 Meters, Utility of the Future.
a. Please provide a description of the "Utility of the Future" equipment included in this account.
b. Please provide any information the company received regarding the warranty or expected life of the equipment included in this account.
c. Please provide any documents that support the response to part (b) of this request.

Confidential Response:

[redacted]

[redacted]

[redacted]

[redacted]

/A

[redacted]

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DUKE ENERGY® CAROLINAS

2018 DEPRECIATION STUDY

CALCULATED ANNUAL DEPRECIATION
ACCRUALS RELATED TO ELECTRIC PLANT
AS OF DECEMBER 31, 2018

Prepared by:

Gannett Fleming

Excellence Delivered As Promised

/A

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DUKE ENERGY CAROLINAS

ACCOUNT 366 UNDERGROUND CONDUIT

SUMMARY OF BOOK SALVAGE

YEAR	REGULAR RETIREMENTS	COST OF REMOVAL AMOUNT	PCT	GROSS SALVAGE AMOUNT	PCT	NET SALVAGE AMOUNT	PCT
2003	36,368	6,274	17		0	6,274-	17-
2004	9,551	1,487	16		0	1,487-	16-
2005	5,606	1,293	23		0	1,293-	23-
2006	18,038	4,077	23		0	4,077-	23-
2007	20,005	5,396	27		0	5,396-	27-
2008	3,856	491	13		0	491-	13-
2009	2,142	92,299		236,636		144,337	
2010	8,738	4,456	51	21	0	4,435-	51-
2011	21,750	250,407			0	250,407-	
2012	2,745		0		0		0
2013	3,204		0		0		0
2014	252,312	60,903	24	91,276	36	30,373	12
2015	307,450	103,248	34	90,017	29	13,231-	4-
2016	286,155	74,123	26		0	74,123-	26-
2017	10,352	124,480		102,250	988	22,230-	215-
2018	36,382	2,070	6		0	2,070-	6-
TOTAL	1,024,654	731,004	71	520,200	51	210,805-	21-
THREE-YEAR MOVING AVERAGES							
03-05	17,175	3,018	18		0	3,018-	18-
04-06	11,065	2,286	21		0	2,286-	21-
05-07	14,550	3,589	25		0	3,589-	25-
06-08	13,966	3,321	24		0	3,321-	24-
07-09	8,668	32,729	378	78,879	910	46,150	532
08-10	4,912	32,416	660	78,886		46,470	946
09-11	10,877	115,721		78,886	725	36,835-	339-
10-12	11,077	84,954	767	7	0	84,948-	767-
11-13	9,233	83,469	904		0	83,469-	904-
12-14	86,087	20,301	24	30,425	35	10,124	12
13-15	187,655	54,717	29	60,431	32	5,714	3
14-16	281,972	79,425	28	60,431	21	18,994-	7-
15-17	201,319	100,617	50	64,089	32	36,528-	18-
16-18	110,963	66,891	60	34,083	31	32,808-	30-
FIVE-YEAR AVERAGE							
14-18	178,530	72,965	41	56,709	32	16,256-	9-

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SHAYE G. WOLF

Curriculum Vitae

1212 Broadway, Suite 800, Oakland, CA 94612
office: (510) 844-7101, cell: (415) 385-5746
swolf@biologicaldiversity.org

CURRENT POSITION

Climate Science Director, Climate Law Institute, Center for Biological Diversity

In my role as Climate Science Director, I provide scientific support for the Center for Biological Diversity's work to fight climate change and protect people and wildlife from the harms of the climate crisis. The Center's Climate Law Institute engages in ambitious, protective and science-based campaigns and litigation to keep fossil fuels in the ground and cut greenhouse gas pollution while promoting the just transition from a fossil fuel economy to 100 percent clean, renewable energy.

EDUCATION

Ph.D. Ecology and Evolutionary Biology, University of California, Santa Cruz, 2002-2007
M.S. Ocean Sciences, University of California, Santa Cruz, 2000-2002
B.S. Biology, Yale University, 1991-1995, *cum laude*

PROFESSIONAL EXPERIENCE

Climate Science Director, Center for Biological Diversity, Climate Law Institute, 2010-present
Staff Scientist, Center for Biological Diversity, Climate Law Institute, 2007-2010
Research Scientist, University of California, Santa Cruz, 2007
Course Instructor, University of California, Santa Cruz, Marine Conservation Biology, 2006
Teaching Assistant, University of California Santa Cruz, 2000-2005; Quantitative Conservation Biology, Ecology and Society, Marine Conservation Biology, Evolution, Life in the Sea
Research Biologist, PRBO Conservation Science, 1999
Research Biologist, Idaho Bird Observatory, 1998
Research Biologist, PRBO Conservation Science, 1998
Research Biologist, Avian Research and Conservation Institute, 1997-1998
Research Intern, US Fish and Wildlife Service, Hawaiian Islands NWR, 1997
Research Intern, National Biological Survey, Hawai'i Volcanoes National Park, 1997
Research Intern, National Park Service, Channel Islands National Park, 1996
Research Technician, Yale University/Smithsonian Tropical Research Institute, Panama, 1995

PUBLICATIONS

Valdivia, A., **S. Wolf**, and K. Suckling, Marine mammals and sea turtles protected under the Endangered Species Act are recovering, PLoS ONE 14(1): e0210164 (2019).

W**olf**, S., B. Hartl, C. Carroll, M.C. Neel, and D.N. Greenwald, Beyond PVA: Why recovery under the Endangered Species Act is more than population viability, BioScience 65: 200-207 (2015).

Whitlock, C., D.A. DellaSala, S. **Wolf**, and C.T. Hanson, Climate Change: Uncertainties, Shifting Baselines, and Fire Management. Pp. 265-289 in *The Ecological Importance of Mixed Severity Fires: Nature's Phoenix*, D.A. DellaSala and C.T. Hanson, eds. Elsevier, Amsterdam, Netherlands (2015).

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Wallace, S.J., S.G. **Wolf**, R.W. Bradley, A.L. Harvey, and V.L. Friesen, The influence of biogeographical barriers on the population genetic structure and gene flow in a coastal Pacific seabird, Journal of Biogeography 42: 390-400 (2015).

Reece, J.S., M. Bilskie, L. Ehrhart, S. Hagen, A. Hays, C. Long, R.F. Noss, D. Passeri, C. Sanchez, M.V. Schwoerer, B. Von Holle, J. Weishampel, and **S. Wolf**, Sea level rise, land use, and climate change influence the distribution of loggerhead (*Caretta caretta*) nests at the largest US rookery at Melbourne Beach, Florida, Marine Ecology Progress Series 493: 259-274 (2013).

Wolf, S.G., M.A. Snyder, W.J. Sydeman, D.F. Doak, and D.A. Croll, Predicting population consequences of ocean climate change for an ecosystem sentinel, the seabird Cassin's auklet, Global Change Biology 16: 1923-1935 (2010).

Wolf, S.G., Distribution and climatic relationships of the American pika (*Ochotona princeps*) in the Sierra Nevada and Western Great Basin, U.S.A; Comment, Arctic, Antarctic, and Alpine Research 42: 490-492 (2010).

Finkelstein, M.E., **S.G. Wolf**, M. Goldman, P.R. Sievert, G. Balogh, H. Hasegawa and D.F. Doak, The anatomy of a (potential) disaster: Volcanoes, behavior, and population viability of the short-tailed albatross (*Phoebastria albatrus*), Biological Conservation 143: 321-331 (2009).

Sydeman, W.J., K.L. Mills, J.A. Santora, S.A. Thompson, D.F. Bertram, K.H. Morgan, M.A. Hipfner, B.K. Wells, and **S.G. Wolf**, Seabirds and climate in the California Current—a synthesis of change, CalCOFI Reports 50: 82-104 (2009).

Wolf, S.G., W.J. Sydeman, J.M. Hipfner, C.M. Abraham, B.R. Tershy, and D.A. Croll, Range-wide reproductive consequences of marine climate variability for the seabird Cassin's auklet, Ecology 90(3): 742-753 (2009).

Finkelstein, M., V. Bakker, D.F. Doak, B. Sullivan, R. Lewison, W.H. Satterwaite, P.B. McIntyre, **S.Wolf**, D. Priddel, J.M. Arnold, R.W. Henry, P. Sievert, and J. Croxall, Evaluating the potential effectiveness of compensatory mitigation strategies for marine bycatch, PLoS One 3(6): e2480 (2008).

Aguirre-Muñoz, A., D.A. Croll, J. Donlan, R.W. Henry III, M.A. Hermosillo, G.R. Howald, B.S. Keitt, L. Luna-Mendoza, M. Rodríguez-Malagón, L.M. Salas-Flores, A. Samaniego-Herrera, J.A. Sanchez-Pacheco, J. Sheppard, B.R. Tershy, J. Toro-Benito, **S. Wolf**, and B. Wood, High-impact conservation: invasive mammal eradications from the islands of western México, Ambio 37: 101-107 (2008).

Wolf, S., B. Keitt, A. Aguirre-Muñoz, E. Palacios, B. Tershy, and D. Croll, Transboundary seabird conservation in an important North American marine ecoregion, Environmental Conservation 33(4): 294-305 (2006).

Wolf, S., C. Phillips, J.A. Zepeda-Dominguez, Y. Albores-Barajas, and P. Martin, Breeding biology of Xantus's Murrelet at the San Benito Islands, Baja California, Marine Ornithology 33(2): 123-129 (2005).

Craig, C.L., **S.G.Wolf**, J.L.D. Davis, M.E. Hauber, and J.L. Maas, Signal polymorphism in the web-decorating spider Argiope argentata is correlated with reduced survivorship and the presence of stingless bees, its primary prey, Evolution 55(5): 986-993 (2001).

NON-ACADEMIC PUBLICATIONS

Blown Away, 10 U.S. Endangered Species Threatened by Climate-Fueled Superstorms, Center for Biological Diversity, 2019

Oil Stain: How Dirty Crude Undercuts California's Climate Progress, Center for Biological Diversity, 2017

Troubled Waters: Offshore Fracking's Threat to California's Ocean, Air and Seismic Stability, Center for Biological Diversity, 2014

On Shaky Ground: Fracking, Acidizing, and Increased Earthquake Risk in California. Earthworks, Center for Biological Diversity, Clean Water Action, 2014

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Deadly Waters: How Rising Seas Threaten 233 Endangered Species. Center for Biological Diversity, 2013
Extinction: It's Not Just for Polar Bears. A Center for Biological Diversity and Care for the Wild International Report and Slideshow. 2010
Not Just a Number: Achieving a CO_2 Concentration of 350 ppm or Less to Avoid Catastrophic Climate Impacts. Center for Biological Diversity and 350.org, 2010
350 Reasons We Need to Get to 350: Species Threatened by Global Warming; An Interactive Installation by the Center for Biological Diversity, 2009
Climate Change Threatens Penguins. Popular science article for actionbioscience, 2009
Petitions to list climate change-threatened species under the Endangered Species Act: Eight pomacentrid reef fish (2012, 90 pp), San Bernardino flying squirrel (2010, 78 pp); 83 coral species (2009, 198 pp); Kittlitz's murrelet (2009, 85 pp); ringed, bearded, and spotted seal (2008, 139 pp); Pacific walrus (2008, 94 pp); ribbon seal (2007, 85 pp); and American pika (2007, 70 pp)

CONFERENCE AND PUBLIC TALKS

American Geophysical Union, Primary Session Convener and Chair: "Aligning U.S. Energy Policy with a 1.5°C Climate Limit: How to Design and Manage a Fossil Fuel Extraction Phase-out and an Equitable Energy Transition," December 2019
Public Forum Organizer, "Beyond Climate Denial: Exposing the Fossil Fuel Industry's Latest Tactics, A Conversation with Michael Mann, Antonia Juhasz, Andrés Soto and Kassie Siegel," December 2019
The Wildlife Society and American Fisheries Society Annual Conference: September 2019
March for Science Bay Area, speaker: April 2018
Society for Conservation Biology: July 2108, July 2016, July 2014, June 2012, July 2008
International Coral Reef Symposium: July 2016
Southwest Climate Summit: October 2015 (poster)
Pacific Seabird Group: February 2015, March 2013, March 2008, February 2006, January 2005
Woods Hole Morrs Colloquium: May 2014
The Wildlife Society, Western Section: February 2013
Ecological Society of America: August 2012
United Nations Framework Convention on Climate Change COP16: December 2010
Public Interest Environmental Law Conference: March 2010
International Marine Conservation Congress: May 2009
North American Ornithological Conference: October 2006

PROFESSIONAL SERVICE

Reviewer for climate reports: Burning the Gas "Bridge Fuel' Myth: Why Gas Is Not Clean, Cheap, or Necessary, Oil Change International (2019); Drilling Towards Disaster: Why U.S. Oil and Gas Expansion is Incompatible with Climate Limits, Oil Change International (2019); The Sky's Limit California, Oil Change International (2018)
Public reviewer for state and national climate assessments: California Climate Adaptation Strategy (Safeguarding California); Second, Third and Fourth National Climate Assessments; IPCC Special Report on 1.5 Degrees
Reviewer for scientific journals: Auk, Conservation Letters, Environment International, Global Change Biology, Marine Ecology Progress Series, Marine Ornithology, Northwest Naturalist, Peer J, Wilson Journal of Ornithology
Guest lecturer: California State University East Bay, Laney College, San Francisco State University, San Francisco Art Institute, University of California Berkeley, University of California Los Angeles, University of California Santa Cruz, University of San Francisco

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PROFESSIONAL MEMBERSHIPS

US Climate Action Network
American Geophysical Union
Society for Conservation Biology
Ecological Society of America
Pacific Seabird Group

WORKING GROUPS

California Climate Adaptation Strategy, key participant and contributor, 2008-present
Coordinator, Scripps's Murrelet and Guadalupe Murrelet Technical Committee, 2005-2017
American Pika Consortium (California and Western) member, 2008-present
Kittlitz's Murrelet and Marbled Murrelet Committee member, Pacific Seabird Group, 2008-2017
Ashy Storm-petrel Working Group member, 2013-2017

BOARD MEMBERSHIP

Wild Nature Institute, 2015 to present

MAJOR FELLOWSHIPS

Switzer Environmental Fellowship, 2000
National Science Foundation Graduate Fellowship, 2000-2004
CDELSI Ocean Health and Environmental Change Graduate Student Fellowship, 2005

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Coal ash settlement provides clarity on closure method and costs

NC COAL ASH SETTLEMENT AGREEMENT

- NC DEQ issued order April 1 requiring low priority sites be fully excavated
- Settlement Agreement reached with NC DEQ and other parties represented by the Southern Environmental Law Center on Dec. 31
  - Seven of the nine basins to be excavated, with ash moved to on-site lined landfills
  - Parties agree to settle and dismiss pending litigation; DEQ and SELC will not challenge the reasonableness, prudence, public interest or legal requirement of Settlement obligations
  - DEQ will expeditiously review and act on all applications by Duke Energy for necessary permits, and cooperate with Duke Energy's efforts to extend deadlines imposed by the Federal CCR rule, as necessary
- Reduces incremental closure costs by $1.5 billion from April 1 order
  - Now estimate total closure costs of $8 to $9 billion in the Carolinas
  - $2.4 billion spent through 2019
  - Majority of remaining expenditures to occur over next 15-20 years
- DEC and DEP revenues forecasted to approximate or exceed annual expenditures, upon finalization of pending rate cases

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Our investor value proposition

DUK
LISTED
NYSE

A SOLID LONG-TERM HOLDING

4.2%
DIVIDEND YIELD(1) WITH DIVIDEND **GROWTH COMMITMENT(2)**

~8-10%
ATTRACTIVE RISK-ADJUSTED **TOTAL SHAREHOLDER RETURN(3)**

4-6%
HIGHLY ACHIEVABLE **EPS GROWTH THROUGH 2023(4)**

CONSTRUCTIVE JURISDICTIONS, LOW-RISK REGULATED INVESTMENTS AND BALANCE SHEET STRENGTH

(1) As of January 7, 2020
(2) Subject to approval by the Board of Directors
(3) Total shareholder return proposition at a constant P/E ratio
(4) Based on adjusted diluted EPS off the midpoint of the original 2019 guidance range, or $5.00 as most recently affirmed in the Third Quarter 2019 Earnings Review and Business Update on November 8, 2019.

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DUKE ENERGY CAROLINAS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20
ALLETE, Inc.	High Price ($)	88.380	88.600	87.830	86.910	82.160	84.710
	Low Price ($)	83.280	83.590	85.130	78.880	78.250	79.400
	Avg. Price ($)	85.830	86.095	86.480	82.895	80.205	82.055
	Dividend ($)	0.588	0.588	0.588	0.588	0.588	0.588
	Mo. Avg. Div.	2.74%	2.73%	2.72%	2.83%	2.93%	2.86%
	6 mos. Avg.	2.80%					
Alliant Energy Corp.	High Price ($)	53.000	54.590	54.430	53.670	55.400	59.740
	Low Price ($)	48.770	50.360	51.580	50.930	52.240	53.320
	Avg. Price ($)	50.885	52.475	53.005	52.300	53.820	56.530
	Dividend ($)	0.355	0.355	0.355	0.355	0.355	0.380
	Mo. Avg. Div.	2.79%	2.71%	2.68%	2.72%	2.64%	2.69%
	6 mos. Avg.	2.70%					
Ameren Corp.	High Price ($)	77.520	80.850	80.050	77.920	77.040	82.410
	Low Price ($)	73.670	73.310	75.260	73.340	73.510	75.540
	Avg. Price ($)	75.595	77.080	77.655	75.630	75.275	78.975
	Dividend ($)	0.475	0.475	0.475	0.475	0.495	0.495
	Mo. Avg. Div.	2.51%	2.46%	2.45%	2.51%	2.63%	2.51%
	6 mos. Avg.	2.51%					
American Electric Power Co.	High Price ($)	91.500	94.890	96.220	94.980	95.770	104.430
	Low Price ($)	87.040	90.080	91.350	88.170	90.210	92.940
	Avg. Price ($)	89.270	92.485	93.785	91.575	92.990	98.685
	Dividend ($)	0.670	0.670	0.670	0.700	0.700	0.700
	Mo. Avg. Div.	3.00%	2.90%	2.86%	3.06%	3.01%	2.84%
	6 mos. Avg.	2.94%					
Avangrid, Inc.	High Price ($)	51.390	52.480	52.238	50.280	52.065	53.940
	Low Price ($)	48.315	49.050	48.250	47.920	48.060	50.210
	Avg. Price ($)	49.852	50.765	50.244	49.100	50.063	52.075
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.53%	3.47%	3.50%	3.58%	3.52%	3.38%
	6 mos. Avg.	3.50%					
CMS Energy Corp.	High Price ($)	63.310	65.310	65.020	64.140	63.440	68.980
	Low Price ($)	57.430	60.100	62.320	59.330	60.250	61.570
	Avg. Price ($)	60.370	62.705	63.670	61.735	61.845	65.275
	Dividend ($)	0.383	0.383	0.383	0.383	0.383	0.383
	Mo. Avg. Div.	2.53%	2.44%	2.40%	2.48%	2.47%	2.34%
	6 mos. Avg.	2.45%					

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DUKE ENERGY CAROLINAS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20
DTE Energy Co.	High Price ($)	131.730	134.370	133.390	127.930	130.700	134.720
	Low Price ($)	124.930	127.160	123.410	120.080	123.130	127.620
	Avg. Price ($)	128.330	130.765	128.400	124.005	126.915	131.170
	Dividend ($)	0.945	0.945	0.945	0.945	1.013	1.013
	Mo. Avg. Div.	2.95%	2.89%	2.94%	3.05%	3.19%	3.09%
	6 mos. Avg.	3.02%					
Evergy, Inc.	High Price ($)	66.000	67.810	66.540	65.630	65.150	72.620
	Low Price ($)	59.600	63.350	62.040	62.330	61.970	62.930
	Avg. Price ($)	62.800	65.580	64.290	63.980	63.560	67.775
	Dividend ($)	0.475	0.475	0.475	0.505	0.505	0.505
	Mo. Avg. Div.	3.03%	2.90%	2.96%	3.16%	3.18%	2.98%
	6 mos. Avg.	3.03%					
Hawaiian Electric Ind.	High Price ($)	45.140	45.960	45.780	45.400	47.640	49.630
	Low Price ($)	42.720	43.240	43.970	42.950	43.330	45.040
	Avg. Price ($)	43.930	44.600	44.875	44.175	45.485	47.335
	Dividend ($)	0.320	0.320	0.320	0.320	0.320	0.320
	Mo. Avg. Div.	2.91%	2.87%	2.85%	2.90%	2.81%	2.70%
	6 mos. Avg.	2.84%					
NextEra Energy, Inc.	High Price ($)	225.570	233.450	239.890	238.890	245.010	270.660
	Low Price ($)	205.780	216.370	226.580	220.660	231.070	237.950
	Avg. Price ($)	215.675	224.910	233.235	229.775	238.040	254.305
	Dividend ($)	1.250	1.250	1.250	1.250	1.250	1.250
	Mo. Avg. Div.	2.32%	2.22%	2.14%	2.18%	2.10%	1.97%
	6 mos. Avg.	2.15%					
Northwestern Corp.	High Price ($)	72.660	76.720	76.180	73.340	73.080	77.340
	Low Price ($)	67.360	71.630	70.950	68.030	69.350	69.690
	Avg. Price ($)	70.010	74.175	73.565	70.685	71.215	73.515
	Dividend ($)	0.575	0.575	0.575	0.575	0.575	0.575
	Mo. Avg. Div.	3.29%	3.10%	3.13%	3.25%	3.23%	3.13%
	6 mos. Avg.	3.19%					
OGE Energy Corp.	High Price ($)	43.530	45.770	45.490	43.770	44.550	46.330
	Low Price ($)	41.390	42.410	42.130	41.790	41.830	43.220
	Avg. Price ($)	42.460	44.090	43.810	42.780	43.190	44.775
	Dividend ($)	0.365	0.365	0.388	0.388	0.388	0.388
	Mo. Avg. Div.	3.44%	3.31%	3.54%	3.62%	3.59%	3.46%
	6 mos. Avg.	3.49%					

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DUKE ENERGY CAROLINAS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20
Otter Tail Corp.	High Price ($)	54.260	55.100	56.690	57.740	53.160	54.300
	Low Price ($)	48.090	50.340	52.560	48.170	48.590	50.830
	Avg. Price ($)	51.175	52.720	54.625	52.955	50.875	52.565
	Dividend ($)	0.350	0.350	0.350	0.350	0.350	0.350
	Mo. Avg. Div.	2.74%	2.66%	2.56%	2.64%	2.75%	2.66%
	6 mos. Avg.	2.67%					
Pinnacle West Capital Corp.	High Price ($)	95.790	98.580	97.520	93.880	90.680	98.810
	Low Price ($)	90.480	91.180	92.060	84.260	84.880	88.100
	Avg. Price ($)	93.135	94.880	94.790	89.070	87.780	93.455
	Dividend ($)	0.738	0.738	0.738	0.783	0.783	0.783
	Mo. Avg. Div.	3.17%	3.11%	3.11%	3.51%	3.57%	3.35%
	6 mos. Avg.	3.30%					
PNM Resources, Inc.	High Price ($)	51.470	52.950	52.980	52.280	51.980	55.240
	Low Price ($)	47.590	48.710	50.330	47.230	47.850	48.520
	Avg. Price ($)	49.530	50.830	51.655	49.755	49.915	51.880
	Dividend ($)	0.290	0.290	0.290	0.290	0.290	0.308
	Mo. Avg. Div.	2.34%	2.28%	2.25%	2.33%	2.32%	2.37%
	6 mos. Avg.	2.32%					
Portland General Electric Co.	High Price ($)	57.270	58.430	57.520	57.920	57.090	61.710
	Low Price ($)	53.470	54.780	55.410	54.240	54.360	54.550
	Avg. Price ($)	55.370	56.605	56.465	56.080	55.725	58.130
	Dividend ($)	0.385	0.385	0.385	0.385	0.385	0.385
	Mo. Avg. Div.	2.78%	2.72%	2.73%	2.75%	2.76%	2.65%
	6 mos. Avg.	2.73%					
Southern Company	High Price ($)	58.840	62.360	62.880	63.290	64.260	71.100
	Low Price ($)	55.380	58.240	60.450	60.380	60.090	62.240
	Avg. Price ($)	57.110	60.300	61.665	61.835	62.175	66.670
	Dividend ($)	0.620	0.620	0.620	0.620	0.620	0.620
	Mo. Avg. Div.	4.34%	4.11%	4.02%	4.01%	3.99%	3.72%
	6 mos. Avg.	4.03%					
WEC Energy Group, Inc.	High Price ($)	96.460	98.190	96.290	94.730	93.430	101.370
	Low Price ($)	85.160	89.020	91.510	86.500	87.410	90.340
	Avg. Price ($)	90.810	93.605	93.900	90.615	90.420	95.855
	Dividend ($)	0.590	0.590	0.590	0.590	0.590	0.590
	Mo. Avg. Div.	2.60%	2.52%	2.51%	2.60%	2.61%	2.46%
	6 mos. Avg.	2.55%					

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DUKE ENERGY CAROLINAS PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Aug-19	Sep-19	Oct-19	Nov-19	Dec-19	Jan-20
Xcel Energy	High Price ($)	64.910	66.050	65.140	63.860	64.670	69.620
	Low Price ($)	58.740	62.190	62.180	59.460	60.850	61.970
	Avg. Price ($)	61.825	64.120	63.660	61.660	62.760	65.795
	Dividend ($)	0.405	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	2.62%	2.53%	2.54%	2.63%	2.58%	2.46%
	6 mos. Avg.	2.56%					
Monthly Avg. Dividend Yield		2.93%	2.84%	2.84%	2.94%	2.94%	2.82%
6-month Avg. Dividend Yield		2.88%					

Source: Yahoo! Finance

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DUKE ENERGY CAROLINAS PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Zacks	(4) Yahoo! Finance
ALLETE, Inc.	5.00%	5.00%	7.20%	7.00%
Alliant Energy Corporation	5.50%	6.50%	5.49%	5.40%
Ameren Corp.	4.50%	6.50%	6.24%	4.60%
American Electric Power Co.	5.50%	4.00%	5.65%	6.05%
Avangrid, Inc.	3.00%	8.50%	7.46%	6.40%
CMS Energy Corporation	7.00%	7.00%	6.14%	7.50%
DTE Energy Company	7.00%	4.50%	6.00%	4.83%
Evergy, Inc.	NMF	NMF	6.57%	6.50%
Hawaiian Electric	3.00%	2.50%	4.22%	3.40%
NextEra Energy, Inc.	10.00%	10.50%	7.98%	7.99%
Northwestern Corporation	4.50%	2.00%	3.53%	3.23%
OGE Energy Corp.	6.50%	6.50%	4.26%	3.50%
Otter Tail Corporation	4.00%	5.00%	7.00%	9.00%
Pinnacle West Capital Corp.	6.00%	4.00%	4.71%	4.41%
PNM Resources, Inc.	7.00%	7.00%	5.73%	6.35%
Portland General Electric Company	6.50%	4.50%	4.91%	4.80%
Southern Company	3.00%	3.50%	4.50%	1.53%
WEC Energy Group	6.00%	6.00%	6.14%	6.05%
Xcel Energy Inc.	6.00%	5.50%	5.70%	6.10%
Average	5.56%	5.50%	5.76%	5.51%
Median	5.75%	5.25%	5.73%	6.05%

Sources: **Value Line Investment Survey, November 15, 2019, December 13, 2019, and January 24, 2020**
Yahoo! Finance and Zacks growth rates retrieved January 14, 2020
NMF = No meaningful figure

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DUKE ENERGY CAROLINAS PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Yahoo! Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	2.88%	2.88%	2.88%	2.88%	2.88%
Average Growth Rate	5.56%	5.50%	5.76%	5.51%	5.58%
Expected Div. Yield	2.96%	2.96%	2.97%	2.96%	2.96%
DCF Return on Equity	***8.52%***	***8.46%***	***8.73%***	***8.47%***	***8.54%***
Method 2:					
Dividend Yield	2.88%	2.88%	2.88%	2.88%	2.88%
Median Growth Rate	5.75%	5.25%	5.73%	6.05%	5.70%
Expected Div. Yield	2.97%	2.96%	2.97%	2.97%	2.97%
DCF Return on Equity	***8.72%***	***8.21%***	***8.70%***	***9.02%***	***8.67%***

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DUKE ENERGY CAROLINAS PROXY GROUP
Capital Asset Pricing Model Analysis

30-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.11%
2	Risk-free Rate of Return, 30-Year Treasury Bond	
3	Average of Last Six Months	2.21%
4	Risk Premium	
5	(Line 1 minus Line 3)	8.90%
6	Comparison Group Beta	0.56
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	4.99%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	7.20%

Duff and Phelps Normalized Risk-free Rate

1	Market Required Return Estimate	11.11%
2	Duff and Phelps Normalized Risk-free Rate	3.00%
3	Risk Premium	
4	(Line 1 minus Line 2)	8.11%
5	Proxy Group Beta	0.56
6	Proxy Group Beta * Risk Premium	
7	(Line 4 * Line 5)	4.55%
8	CAPM Return on Equity	
9	(Line 2 plus Line 7)	7.55%

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DUKE ENERGY CAROLINAS PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

30 Year Treasury Bond Data

	Avg. Yield
August-19	2.12%
September-19	2.16%
October-19	2.19%
November-19	2.28%
December-19	2.30%
January-20	2.22%
6 month average	2.21%

Source: www.federalreserve.gov

Value Line Market Return Data:

Forecasted Data:	
Value Line Median Growth Rates:	
Earnings	11.00%
Book Value	8.00%
Average	9.50%
Average Dividend Yield	1.06%
Estimated Market Return	10.61%
Value Line Projected 3-5 Yr.	
Median Annual Total Return	11.00%
Average Annual Total Return	12.21%
Average	11.61%
Average of Projected Mkt. Returns	11.11%

Source: Value Line Investment Survey for Windows, Jan. 10, 2020

Comparison Group Betas:

	Value Line
ALLETE, Inc.	0.65
Alliant Energy Corporation	0.60
Ameren Corp.	0.55
American Electric Power Co.	0.55
Avangrid, Inc.	0.40
CMS Energy Corporation	0.50
DTE Energy Company	0.55
Evergy, Inc.	NMF
Hawaiian Electric	0.55
NextEra Energy, Inc.	0.55
Northwestern Corporation	0.60
OGE Energy Corp.	0.75
Otter Tail Corporation	0.70
Pinnacle West Capital Corp.	0.50
PNM Resources, Inc.	0.60
Portland General Electric Company	0.55
Southern Company	0.50
WEC Energy Group	0.50
Xcel Energy Inc.	0.50
Average	0.56

Source: Value Line Investment Survey

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DUKE ENERGY CAROLINAS PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Arithmetic Mean	Adjusted Arithmetic Mean
CAPM with Current 30-Year Treasury Yield		
Long-Term Annual Return on Stocks	11.90%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	5.00%	
Historical Market Risk Premium	6.90%	6.14%
Proxy Group Beta, Value Line	0.56	0.56
Beta * Market Premium	3.87%	3.45%
Current 30-Year Treasury Bond Yield	2.21%	2.21%
CAPM Cost of Equity, Value Line Beta	**6.08%**	**5.66%**
CAPM with D&P Normalized Risk-Free Rate		
Historical Market Risk Premium	6.90%	6.14%
Proxy Group Beta, Value Line	0.56	0.56
Beta * Market Premium	3.87%	3.45%
D&P Normalized Risk-Free Rate	3.00%	3.00%
CAPM Cost of Equity, Normalized Risk-Free Rate	**6.87%**	**6.45%**

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Line No.	Description	DEC Requested Cap. Structure	North Carolina Retail Operations — DE Carolinas Proposed Return: Requested Retail Rate Base	DE Carolinas Proposed Return: Embedded Cost/ Return %	DE Carolinas Proposed Return: Grossed Up Operating Income	NC Attorney General Proposed Return: 2018 Actual Cap. Structure	NC Attorney General Proposed Return: Requested Retail Rate Base	NC Attorney General Proposed Return: Embedded Cost/ Return %	NC Attorney General Proposed Return: Grossed Up Operating Income
1	Long-term debt	47.00%	$ 7,290,932	4.51%	$ 328,821	48.50%	$ 7,523,621	4.51%	$ 339,315
2	Common Equity	53.00%	8,221,689	10.30%	$ 1,110,311	51.50%	7,989,000	9.00%	942,717
3	Total	100.00%	$ 15,512,620		$ 1,439,132	100.00%	$ 15,512,620		$ 1,282,032
4	Increased revenue requirement from DEC Cost of Capital								157,100

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Duke Energy Carolinas, LLC
Balance Sheet
As of December 31, 2018

Line No.		Amount
	ASSETS	
	UTILITY PLANT	
1	Utility Plant (101-106,114)	$ 41,161,863,023
2	Construction Work in Progress (107)	1,632,658,461
3	Total Utility Plant	42,794,521,484
4	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	15,937,831,422
5	Net Utility Plant	26,856,690,062
6	Nuclear Fuel in Process of Ref., Conv., Enrich., and Fab (120.1)	276,467,667
7	Nuclear Materials and Assemblies - Stock Account (120.2)	1
8	Nuclear Fuel Assemblies in Reactor (120.3)	1,152,233,077
9	Spent Nuclear Fuel (120.4)	475,269,001
10	(Less) Accum. Provision for Amort. of Nuclear Fuel Assemblies (120.5)	1,089,674,019
11	Net Nuclear Fuel	814,295,727
12	Total Utility Plant, Net	27,670,985,789
13	Utility Plant Adjustments (116)	1,012,652
	OTHER PROPERTY & INVESTMENTS	
14	Non Utility Property (121)	119,145,876
15	(Less) Accum. Prov. for Depr. and Amort. (122)	41,247,904
16	Investment in Subsidiary Companies (123.1)	13,114,081
17	Other Investments (124)	94,370
18	Other Special Funds (128)	3,771,013,238
19	Long Term Portion of Derivative Assets - Hedges (176)	207,518
20	Total Other Property and Investments	3,862,327,179
	CURRENT AND ACCRUED ASSETS	
21	Cash (131)	32,258,744
22	Working Funds (135)	300,000
23	Customer Accounts Receivable (142)	456,075,858
24	Other Accounts Receivable (143)	166,247,610
25	(Less) Accum. Prov. for Uncollectible Account - Credit (144)	9,138,649
26	Accounts Receivable from Associated Companies (146)	244,703,341
27	Fuel Stock (151)	220,760,888
28	Plant Material and Operating Supplies (154)	682,226,291
29	Other Materials and Supplies (156)	103,378
30	Allowances (158.1 and 158.2)	46,163,658
31	Store Expenses Undistributed (163)	45,188,768
32	Prepayments (165)	23,491,197
33	Rents Receivable (172)	236,004
34	Accrued Utility Revenue (173)	267,458,428
35	Miscellaneous Current and Accrued Assets (174)	12,410,350
36	Derivative Instrument Assets Hedges (176)	508,451
37	(Less) Long Term Portion of Derivative Instruments Assets - Hedges	207,518
38	Total Current and Accrued Assets	2,188,786,799
	DEFERRED DEBITS	
39	Unamortized Debt Expenses (181)	57,472,450
40	Other Regulatory Assets (182.3)	3,988,381,653
41	Preliminary Survey and Investigation Charges (183)	9,500,938
42	Clearing Accounts (184)	910,613
43	Miscellaneous Deferred Debits (186)	1,091,462,938
44	Unamortized Loss on Reacquired Debt (189)	57,438,955
45	Accumulated Deferred Income Taxes (190)	2,697,261,240
46	Total Deferred Debits	7,902,428,787
47	**Total Assets**	**$ 41,625,541,206**

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Sep 30 2019

Duke Energy Carolinas, LLC
Balance Sheet
As of December 31, 2018

Line No.		Amount
	CAPITALIZATION AND LIABILITIES	
	PROPRIETARY CAPITAL	
1	Other Paid In Capital (208-211)	$ 3,725,067,453
2	Retained Earnings (215, 215.1, 216)	7,963,467,563
3	Unappropriated Undistributed Subsidiary Earnings (216.1)	4,810,163
4	Accumulated Other Comprehensive Income (219)	(6,167,891)
5	Total Proprietary Capital	11,687,177,288
	LONG-TERM DEBT	
6	Bonds (221)	9,909,011,177
7	Advances from Associated Companies (223)	300,000,000
8	Other Long Term Debt (224)	698,261,570
9	(Less) Unamortized Discount on LT Debt (226)	23,479,383
10	Total Long Term Debt	10,883,793,364
	OTHER NONCURRENT LIABILITIES	
11	Obligations Under Capital Leases (227)	103,966,297
12	Accumulated Provision for Property Insurance (228.1)	108,413,219
13	Accumulated Provision for Injuries and Damages (228.2)	633,919,490
14	Accumulated Provision for Pensions and Benefits (228.3)	94,896,447
15	Accumulated Miscellaneous Operating Provisions (228.4)	4,538,620
16	Accumulated Provision for Rate Refund (229)	182,332,111
17	LT Portion of Derivative Instrument Liabilities - Hedges	9,127,400
18	Asset Retirement Obligations (230)	3,948,779,041
19	Total Other Noncurrent Liabilities	5,085,972,625
	CURRENT AND ACCRUED LIABILITIES	
20	Accounts Payable (232)	973,427,628
21	Notes Payable to Associated Companies (233)	438,690,000
22	Accounts Payable to Associated Companies (234)	252,784,648
23	Customer Deposits (235)	126,584,652
24	Consolidated Taxes Accrued (236)	170,427,273
25	Interest Accrued (237)	102,018,472
26	Tax Collections Payable (241)	12,372,163
27	Miscellaneous Current and Accrued Liabilities (242)	372,526,662
28	Obligations Under Capital Leases - Current (243)	5,304,078
29	Derivative Instrument Liabilities (244)	9,410,350
30	Derivative Instrument Liabilities - Hedges (245)	21,253,078
31	(Less) LT Portion of Derivative Instrument Liabilities - Hedges	9,127,400
32	Total Current and Accrued Liabilities	2,475,671,604
	DEFFERED CREDITS	
33	Accumulated Deferred Investment Tax Credits (255)	231,369,819
34	Other Deferred Credits (253)	573,392,182
35	Other Regulatory Liabilities (254)	4,301,714,243
36	Accumulated Deferred Income Taxes Oth Property (282)	4,343,192,939
37	Accum Deferred Income Tax Other (283)	2,043,257,142
38	Total Deferred Credits	11,492,926,325
39	**Total Capitalization and Liabilities**	**$ 41,625,541,206**

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Duke Energy Carolinas, LLC | **Speros Exhibit 1**
Income Statement | **Docket No. E-7 Sub 1214**
For The Test Period (12 Months) Ended December 31, 2018 | **Page 3 of 4**

Line No.		Amount
1	**Operating Revenues (400)**	$ 7,273,364,536
	Operating Expenses	
2	Operation Expenses (401)	3,158,322,869
3	Maintenance Expenses (402)	693,767,447
4	Depreciation Expenses (403)	1,029,546,198
5	Amortization and Depletion of Utility Plant (404-405)	65,860,546
6	Regulatory Debits (407.3)	149,999,980
7	(Less) Regulatory Credits (407.4)	51,895,694
8	(Less) Gains from Disposition of Allowances (411.8)	250,563
9	Total Depreciation and Amortization Expenses	1,193,761,593
10	Taxes Other Than Income Taxes (408.1)	291,829,421
11	Total Operating Expense Before Income Taxes	5,337,681,330
12	Income Taxes - Federal (409.1)	(3,506,659)
13	Income Taxes - Other (409.1)	7,058,710
14	Provision for Deferred Income Taxes (410.1)	1,425,900,089
15	(Less) Provision for Deferred Income Tax Credit (411.1)	1,088,738,036
16	Investment Tax Credit Adjustment Net (411.4)	(5,258,630)
17	Total Income Taxes On Operating Income	335,455,474
18	**Total Utility Operating Expenses**	**5,673,136,804**
19	**Net Utility Operating Income**	**1,600,227,732**
	Other Income	
20	(Less) Costs and Exp. of Merchandising, Job & Contract Work (416)	110,300
21	Revenues from Nonutility Operations (417)	21,115,902
22	(Less) Expenses of Nonutility Operations (417.1)	19,614,542
23	Non Operating Rental Income (418)	(2,946,961)
24	Interest and Dividend Income (419)	927,820
25	Allowance for Other Funds Under Construction (419.1)	73,017,943
26	Miscellaneous Nonoperating Income (421)	19,209,311
27	Total Other Income	91,599,173
	Other Income Deductions	
28	Loss on Disposition of Property (421.2)	392,522
29	Miscellaneous Amortization (425)	9,979
30	Donations (426.1)	9,525,160
31	Life Insurance (426.2)	(60,141)
32	Penalties (426.3)	1,830,590
33	Exp. For Certain Civic, Political and Related Activity (426.4)	4,083,343
34	Other Deductions (426.5)	197,967,254
35	Total Other Income Deductions	213,748,707
	Taxes Applicable to Other Income and Deductions	
36	Taxes Other than Income Taxes (408.2)	3,463,726
37	Income Taxes - Federal (409.2)	(4,970,131)
38	Income Taxes - Other (409.2)	(463,781)
39	Provision for Deferred Income Taxes (410.2)	19,094,320
40	(Less) Provision for Deferred Income Taxes - Cr (411.2)	47,570,994
41	Total Taxes on Other Income and Deductions	(30,446,860)
42	**Net Other Income and Deductions**	**(91,702,674)**
	Interest Charges	
43	Total Interest on Long - Term Debt (427)	457,531,046
44	Amortization of Debt Discount and Exp (428)	6,364,114
45	Amortization of Loss on Reacquired Debt (428.1)	6,441,077
46	Interest on Debt to Associated Companies (430)	16,249,126
47	Other Interest Expense (431)	(13,246,775)
48	(Less) Allowance for Borrowed Funds Used During Construction - Cr (432)	35,192,184
49	Net Interest Charges	438,146,404
	Income Before Extraordinary Items	**1,070,378,654**
	Extraordinary Items	
	Extraordinary Deductions (435)	-
	Net Extraordinary Items	-
	Income Taxes Federal and Other (409.3)	-
	Extraordinary Items After Taxes	-
50	**Net Income**	**$ 1,070,378,654**

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Sep 30 2019

Duke Energy Carolinas, LLC
Statement of Capitalization
As of December 31, 2018

Long-Term Debt

Line Number	Description	Rate	Interest Type	Maturity Date	Outstanding Balance	Percent of Total
1	Intercompany borrowings (Money pool)	2.794%	Floating	03/16/23	$ 300,000,000	
2	First Mortgage Bond	4.300%	Fixed	06/15/20	450,000,000	
3	First Mortgage Bond	8.950%	Fixed	07/01/27	9,011,177	
4	First Mortgage Bond	6.000%	Fixed	01/15/38	500,000,000	
5	First Mortgage Bond	6.050%	Fixed	04/15/38	600,000,000	
6	First Mortgage Bond	5.300%	Fixed	02/15/40	750,000,000	
7	First Mortgage Bond	3.900%	Fixed	06/15/21	500,000,000	
8	First Mortgage Bond	4.250%	Fixed	12/15/41	650,000,000	
9	First Mortgage Bond	3.750%	Fixed	06/01/45	500,000,000	
10	First Mortgage Bond	4.000%	Fixed	09/30/42	650,000,000	
11	First Mortgage Bond	2.500%	Fixed	03/15/23	500,000,000	
12	First Mortgage Bond	3.875%	Fixed	03/15/46	500,000,000	
13	First Mortgage Bond	2.950%	Fixed	12/01/26	600,000,000	
14	First Mortgage Bond	3.700%	Fixed	12/01/47	550,000,000	
15	Tax-Exempt Bonds	4.625%	Fixed	11/01/40	50,000,000	
16	Tax-Exempt Bonds	4.625%	Fixed	11/01/40	50,000,000	
17	Tax-Exempt Bonds	4.375%	Fixed	10/01/31	71,605,000	
18	Tax-Exempt Bonds	4.375%	Fixed	10/01/31	71,595,000	
19	Secured Debt (DERF)*	3.463%	Floating	12/15/20	275,000,000	
20	Secured Debt (DERF)*	3.457%	Floating	12/15/20	175,000,000	
21	Unsecured Debt	6.000%	Fixed	12/01/28	300,000,000	
22	Unsecured Debt	6.450%	Fixed	10/15/32	350,000,000	
23	Unsecured Debt	6.100%	Fixed	06/01/37	500,000,000	
24	First Mortgage Bond	3.050%	Fixed	03/15/23	500,000,000	
25	First Mortgage Bond	3.950%	Fixed	03/15/48	500,000,000	
26	First Mortgage Bond	3.350%	Fixed	05/15/22	350,000,000	
27	First Mortgage Bond	3.950%	Fixed	11/15/28	650,000,000	
28	Gains on Terminated Swaps				5,061,570	
29	Unamortized Debt (Discount)/Premium				(23,479,382)	
30	**Total Long Term Debt**				**$ 10,883,793,365**	
31	Capital Leases				$ 109,270,375	
32	**Total Long Term Debt and Capital Leases**				**$ 10,993,063,740**	**48.5%**

Regulatory Common Equity

33	Other Paid in Capital				$ 3,725,067,453	
34	Retained Earnings				7,968,277,726	
35	Accumulated Other Comprehensive Income				(6,167,891)	
36	Unappropriated Undistributed Subsidiary Earnings				(4,810,163)	
37	**Total Common Equity**				**$ 11,682,367,125**	**51.5%**
38	**Total Regulatory Capitalization**				**$ 22,675,430,865**	**100.0%**

*DERF - Duke Energy Receivable Finance Company, LLC

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the Test Year Ended December 31, 2018
Dollars in Thousands

No.	Description	Actual Annual Amount [A]	Lead (Lag) Days [B]	Weighted Amount [C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag		40.09	
2				
3	Operation and Maintenance Expense	2,559,661,028	28.87	73,903,776,282
4	Depreciation and Amortization	838,804,844	0.00	0
5	Taxes Other Than Income Taxes	194,680,961	160.71	31,287,269,740
6	Interest on Customer Deposits	7,129,673	218.40	1,557,120,627
7	Income Taxes	224,997,489	0.48	107,265,513
8	Investment of Tax Credit	(3,525,573)	0.00	0
9	Net Operating Income	1,082,335,768	24.97	27,025,316,831
10	Total Requirements (Sum L3 through L9)	4,904,084,190	27.30	133,880,748,992
11				
12	Revenue Lag Days (L1)		40.09	
13	Requirements Lead Days (-L10)		(27.30)	
14	Net Lag Days (L12 + L13)		12.79	
15	Daily Requirements (Line 10, Col. A divided by 365)			13,435,847
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			171,869,445
18	Add: Cash Working Capital Related to NC Sales Tax			5,870,792
19	Total Cash Working Capital Requirements (L17 + L18)			177,740,237
20				
21	**Calculation of Total Company and Jurisdictional Amounts:**			
22	NC Retail Factor "All - Rate Base x CWC" Allocation Factor			68.1442%
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 260,829,438

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Duke Energy Carolinas, LLC

Lead-Lag Study

May 2019

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Building a better working world

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Charlotte, NC 28202

Tel: +1 704 372 6300
ey.com

May 22, 2019

Abbe Greenfield
Rate Case Planning & Execution, Duke Energy Carolinas, LLC
526 South Church Street
Charlotte, NC 28202

Mrs. Greenfield:

We have completed our procedures with respect to analyzing a detailed lead-lag study for Duke Energy Carolinas, LLC ("the Company" or "DEC") focused on retail operations in the state of North Carolina. Our procedures were performed in accordance with our Statement of Work, dated April 19, 2018. Our report consists of three parts. We summarize our scope, approach and findings in a narrative executive summary; we present our detailed findings in a schedule that provides the lag and lead days by revenue and expense component used by DEC in its cost of service filings; and we provide an appendix that provides the company's summary calculations with a reference to 19 underlying detail schedules.

The information provided in this report is intended to be used to support the Company's request for a cash working capital allowance to be included in the Company's requested rate base to be authorized by the North Carolina Utility Commission. The report is not intended to be, and should not be, used without our prior written consent by any other party or for any other purpose. Our calculations relied on underlying accounting information provided by the Company. We did not audit that underlying accounting information.

We value the opportunity to work with you and appreciate the cooperation and assistance provided. We would be pleased to discuss any aspect of our work or this report with you or other members of management at your convenience. If you have questions, please call Jake Van Reen at (617) 375-2446.

Thank you,

Jake Van Reen

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Executive Summary

1.1. Organization of Report

This report is composed of three parts: Executive Summary, Detailed Findings, and Appendix.

The Executive Summary provides background on the engagement, the purpose and scope of the lead-lag study, the standards applied and the relation to previous studies, and a discussion of key findings.

The Detailed Findings are provided in a DEC Lead-Lag Summary schedule contained within E-1 Item 14. This schedule provides the lag and lead days by revenue and expense component used by the Company in its cost of service filings. The summary was agreed to the underlying supporting schedules.

1.2. Background

Duke Energy Company, LLC ("Duke") engaged Ernst & Young ("EY") to support the preparation of a lead-lag study for Duke's retail operations in the state of North Carolina. The study will be used to support the Company's request for a cash working capital allowance to be included in the requested rate base. This report presents the methodology and approach used in the study and the results covering the twelve-month period ending December 31, 2017, subject to known changes.

The Company last presented a lead-lag study to the North Carolina Utility Commission ("NCUC" or the "Commission") for the twelve-month period ending December 31, 2009. This report presents the lead-lag study in the same general format and applies the same methodologies where applicable. Since that time, there are assumed to have been no significant changes in the operating and regulatory environments that would materially affect the calculation of the cash working capital requirements. To confirm this assumption, EY interviewed Duke personnel and a contractor responsible for compiling the study. EY also analyzed certain of the Company's financial statements and riders to DEC's regulatory requirements for the same purpose.

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1.3. Cash Working Capital

1.3.1. Purpose of lead-lag study

The lead-lag study is designed to measure the average amount of capital, over and above the investments in plant, and other separately identified rate base items, provided by investors to bridge the gap between the time expenditures are required to provide service and the time collections of revenues are received for the service. This quantity is referred to as cash working capital. Cash working capital is more comprehensive than simply financing the lag between Company payments and receipts, as investor capital is required to finance the lag in the recovery of the entire cost of service, including depreciation and cost of capital.

1.3.2. Cash working capital requirement

A requirement for cash working capital represents the amount necessary to provide the utility with an opportunity to appropriately earn an authorized return on all capital invested in utility operations. Unless all capital supplied by investors has that opportunity, investors will not be fully compensated for the capital supplied and the objective of the cash working capital requirement will not be met. Consequently, the key test of the adequacy of the cash working capital requirement should be whether the inclusion of such an amount when added to net utility plant and other items includible in the rate base will produce a fair representation of the capital on which there should be an opportunity to earn a return.

1.3.3. Lead-lag study methodology

To the extent applicable, this study tracks the methodology used in the previous rate filings of the Company and decisions of the NCUC.

The lead-lag study measures the difference in time frames between: (1) when service is rendered and the revenue for that service is received ("revenue lag"); and (2) when the costs of providing service are incurred (including costs of fuel and purchased power, labor, materials, services, etc.) and the time for which those costs are paid ("expense lead"). The difference between these lag periods is expressed in terms of days. The calculated number of days multiplied by the average daily operating revenues or cost of service produces the cash working capital required by the Company.

To fully identify cash working capital requirements, there are additions and deductions to the

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amount calculated in the lead-lag study. This is done to adjust for items not accounted for in rate base. For example, we must add operational cash requirements and add or deduct any other requirements for, or sources of, cash working capital (such as prepayments, reserves, and items capitalized prior to payment). In previous rate case proceedings, these adjustments have been considered separately from the lead-lag study, so they are not considered in this report.

1.3.4. Results of lead-lag study for DEC retail electric operations

The following section provides a summary of the most significant revenue lags and expense leads calculated. Additional detailed identification of the calculated revenue lags and expense leads is included in the attached schedule entitled E-1 Item 14 ("the summary schedule").

1.4. Revenue Lag

The revenue lag measures the time between service delivery to customers and the collection of revenue for service from customers. For the year ending December 31, 2017, approximately 99% of North Carolina retail jurisdictional revenue was received from cycle billed customers (customers billed on a periodic basis) and the large customer billing group, DEC's Customer Billing Information System (CBIS) and Lodestar Billing Expert systems, respectively.

The revenue lag for these services is the sum of three components: (i) service lag, (ii) billing lag and (iii) collection lag.

The first component is service lag. The Company reads the meters on a monthly basis; therefore the average time between meter reads is 30.42 days (365 days in a year divided by 12 monthly meter reads). Dividing by two provides the midpoint in time, or the average time between when service is provided and the meter read, for a service lag of 15.21 days. (See summary schedule line 4.)

The second component of the total revenue lag is billing lag, the time from the meter reading to when the customer is billed and the bill is posted in the Company's accounts receivable system. Most customers are billed the next business day after the meter is read. Taking into account weekends and holidays, the calculation of the total billing lag is 1.74 days. (See summary schedule line 11.) This amount differs from the previous study, which deemed the

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billing lag to be at approximately half a day, as the previous study did not account for weekends and holidays.

The third component of the total revenue lag is the collection lag, the period from the billing date to the time the customer pays their bill (i.e., the date cash payments are credited on the accounts receivable records). This component of the revenue lag is measured by dividing average daily accounts receivable (based on a thirteen-month average) by average daily sales. Collection policies for retail operations in North Carolina are governed by NCUC rules. We calculated the collection lag to be 22.63 days. (See summary schedule line 15.)

Adding these three components together produced a total lag of 39.58 days in the collection of revenues for services provided to cycle-read and large customer billing group customers on electric delivery rate schedules. (See summary schedule line 17.)

EY did not factor in the potential impact of float. The Company experiences two float periods - the time from when funds are received from customers until the funds clear the banks, and the time between when the Company sends a check to pay for services and when those checks are deposited. In the first instance, the Company's cash requirements are increased by the float (i.e. funds are not actually available until after the deposits clear). However, in the second instance, the Company's cash requirements are reduced by the float. Given the relative levels of electronic funds transfers in the Company's payments versus in its receipts, we are confident that the float for revenue is larger than the float for expense. Accordingly, excluding float in this instance is a conservative assumption that would not harm the ratepayer.

In addition to the above, the Company records a variety of additional and miscellaneous revenues which are also applicable to the North Carolina retail jurisdiction. These include intersystem sales for resale, miscellaneous riders (unbilled fuel and deferred revenue), provisions for refunds, forfeited discounts, rental income, pole and line attachment, and revenue from the transmission of electricity to others. To calculate the overall average revenue lag, we calculated the revenue lags for each of the additional and miscellaneous revenues. The total revenue lag for DEC is 38.01 days. (See summary schedule line 80.)

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1.5. Expense lead

There are several major categories of expense including:

- O&M Fuel
- O&M Purchased Power
- Labor and Benefits
- Other specifically identified O&M
- Other O&M sampled
- Depreciation and Amortization
- Taxes other than Income
- Interest on Customer Deposits
- Income Taxes
- Net Operating Income

Each of the above are described in more detail below.

1.5.1. O&M Fuel

O&M Fuel costs consist of coal, oil, and natural gas purchases. Fuel is the largest cost category, accounting for approximately 20% of the cost of service for the year ending December 31, 2017. Coal costs include two major components: coal commodity purchases and coal transportation costs. The cost of coal purchases and transportation are inventoried and, by NCUC precedent, coal fuel inventories are included in rate base. However, the cash working capital requirement must recognize the cash available to the Company stemming from the time between receipt of coal and the subsequent payment of the fuel or transportation invoice.

DEC receives thousands of coal deliveries at its coal generating stations each year. DEC employs the following coal payment terms: (i) contract deliveries made between the 1st and 15th of the current month are paid by the 30th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days); (ii) contract deliveries made between the 1st and 15th of the current month are paid by the 15th of the following month or contract deliveries made between the 16th and 31st of the current month are paid by the 30th of the following month (37.5 days); (iii) contract deliveries made between the 1st and 31st of the current month are paid by the 30th of the following month (45 days); (iv) contract deliveries made between the 1st and 15th of the current

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month are paid by the 25th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 10th of the following month (17.5 days); (v) contract deliveries made between the 1st and 31st of the current month are paid by the 20th of the following month (35 days); and (vi) contract deliveries paid 10 days after ship date (10 days). Vendor contracts require DEC payments to be received by the vendor by the noted due date.

DEC employs the following vendor coal transportation contract terms: (i) coal freight payments 15 days after the ship date (15 days); (ii) coal freight received between the 1st and 15th of the current month are paid by the 30th of the current month or coal freight received between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days). The weighted average coal and coal freight expense lead is 20.79 days. (See summary schedule line 93.)

Nuclear fees have a calculated expense lead of (34.15) days. (See summary schedule line 119.)

Small amounts of oil and natural gas are also used as a fuel for generation. Unlike coal or oil, natural gas is not stored and inventoried, rather it is purchased as it is used to generate electricity. Therefore, the expense lag for natural gas is computed conventionally as the difference between the service period and the date of payment. Since Duke is not storing natural gas to be used for generation, the service period is considered to be the mid-point of the billing period from the gas supplier, and the payment date is simply the date of payment. We calculated the natural gas invoices and their computed expense leads as 38.00 days. (See summary schedule line 107.)

1.5.2. O&M Purchased Power

DEC provided listings of all transactions for each of the purchased power accounts for our analysis. We weighted the individual invoices by dollar amount, resulting in an overall expense lead of 39.00 days. (See summary schedule line 115.)

1.5.3. O&M Labor and Benefits

Labor and benefits comprised approximately 12% of the cost of service for the year ending December 31, 2017. Labor costs fall into three categories: net payroll, deductions from payroll,

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and taxes. In turn, the Company's payroll consists of two primary categories, semi-monthly payroll and bi-weekly payroll, with lesser amounts of incentive pay. We identified each pay period and the payment dates corresponding to that pay period. For payroll related deductions (income taxes, social security, etc.) we identified each deduction and when the payments for each deduction were made.

1.5.4. Other Specifically Identified O&M

Other specifically identified O&M categories include the following accounts:

- Uncollectible accounts
- Regulatory expenses
- Insurance expenses
- Injuries and damages – workers compensation

Uncollectible accounts expenses result from the timing of the write-off of customer accounts receivable as uncollectible. By NCUC practice, these expenses are valued at zero days expense lead.

We calculated expense lead days for regulatory expenses, insurance expenses and injuries and damages expenses by analyzing service periods, payment amounts and payment patterns. Insurance expenses and injuries and damages are payments for insurance policies. By their nature, insurance policies are paid prior to the service period for coverage; both have negative expense leads. (See summary schedule lines 130 and 132.)

1.5.5. Other O&M Sampled

To determine the expense lead for other O&M not specifically analyzed (summary schedule line 134), the Company provided EY with a listing of cash disbursements for the twelve-month period ending December 31, 2017. We removed records for capital costs, non-electric O&M costs, and any costs already analyzed, resulting in a sample population consisting of $757,657,609 and 38,262 rolled vouchers (Note: there were over 510,000 records, but multiple disbursements were made on the same voucher; since the voucher was the unit sampled, the records were rolled up to the voucher level). From that population, a stratified random sample in nine strata, based on the invoice dollar amount, was selected (274 total

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selections) for sample testing. For each item sampled, the supporting documentation was obtained and analyzed. For purposes of the analysis, service period information was either provided by Duke based on the supporting documentation or, in instances where the service period was not available, the invoice date was provided. The paid dates utilized in the analysis were taken from the Company's payables ledger.

The estimated weighted average expense lead calculated from the sample was 39.98 days, plus or minus 5.85 days with 90% confidence. This contrasts to the 25.72 days calculated for the other O&M sample from the previous lead-lag study. When asked about the increase in days, the client informed us that Duke has 45-day payment terms, and has been following these more closely than previously. EY used statisticians to sample the Other O&M population.

In addition, approximately 2% of the other O&M were employee expenses. These were included in our sample, and the client selected large dollar amounts and filled in the service period and payment date. For the remainder, we calculated the average lead lag days based on the credit card payment dates; this made up 63% of the sample. All credit cards have the same cut off dates for service periods and the same payment dates. As a result, these were not sampled. Rather the expense lead was calculated as the average time from the midpoint of the service period to the payment date.

1.5.6. Depreciation and Amortization

Expenses for depreciation and amortization are the result of prior cash transactions that are not initially charged to expense. A zero lag is applied because the expense is deducted from rate base when the expense is recorded. By way of example, investors supply cash for capital investments such as plant assets. A cash transaction occurs when a plant asset is acquired. The plant asset is included in rate base and the cash investment earns a return until depreciation expense is recorded. When depreciation expense is recorded, the amount of the expense is removed from rate base and the expense becomes recoverable in cost of service. However, the cash is not recovered until revenues are collected (*e.g.*, after the revenue lag). Thus, depreciation expense is included in the lead-lag study with a zero expense lead to provide a return for the period from when the depreciation expense is booked and removed from rate base until it is recovered from revenues.

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1.5.7. Taxes Other than Income

Expense leads for taxes other than income taxes consider the timing between when the taxes are assessed, and the related service period. Some taxes are assessed and paid prior to the start of the service period and others are paid after a significant portion of the service period has occurred. Overall the average expense lead on taxes other than income for the period ending December 31, 2017 was 164.74 days. (See summary schedule line 147.) Per the 2009 lead-lag study, the average expense lead on taxes other than income was 83.21. The increase in the number of lead lag days is the result of tax reform occurring in 2014, which significantly reduced the franchise tax (historically paid soon after each billing cycle). This had previously offset the impact of property taxes, which are paid nearly a year after the service period begins. Additionally, there was a considerable increase in the level of property taxes between 2009 and 2017.

1.5.8. Interest on Customer Deposits

Interest is credited to customers who are required to maintain deposits, and the interest is paid either when the deposit is returned or at periodic intervals. The expense lead on customer deposits is 218.40 days. (See summary schedule line 149.)

1.5.9. Income Taxes

Income taxes has two major components, current and deferred income taxes. In turn, current income taxes include taxes for the current year and taxes for prior periods. The expense lead for current income taxes for the current year is the result of the statutory payment dates. Similar to the rationale for depreciation expense, the deferred tax expense lead is zero days because net deferred tax liabilities are deducted from rate base when the expense is recorded. The expense lead on Net Income Taxes is 16.76 days. (See summary schedule line 156.)

1.5.10. Net Operating Income

Net operating income is the return on invested capital, just as depreciation expense is a return on invested capital. Like depreciation expense, a zero lag was assigned to net operating income in recognition of the fact that the return is earned when the service is provided. Because the return is earned when the service is provided, it would be inappropriate to consider subsequent below the line treatment of net operating income. Therefore we did not further analyze the subsequent use of net operating income for interest, dividends or reinvestment.

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1.5.11. Cash Working Capital Impacts of Pass Through Items

As noted, to fully identify the cash working capital requirements, to the amount calculated in the lead lag study we must add operational cash requirements and add or deduct any other requirements for or sources of cash working capital. One item the Company has not included elsewhere and is therefore considered here is pass through taxes. Pass through taxes are similar to taxes other than income except the payment is due from customers not the company. The primary pass through tax is the North Carolina utility sales tax. The Company collects these pass-through taxes from customers in their bills and pays the tax to the State. The tax is not a Company expense because the Company is merely a conduit of the payments from customers to the state. But, to the extent the Company pays the tax before the funds are received from customers, investors in the Company need to provide the cash to finance the time between payment and recovery. The impact on total DEC cash working capital requirements due to the NC sales pass through tax is $6,694,345. (See summary schedule line 167.)

Conclusion

We have calculated the revenue lag days and expense lead days documented in the schedule described above. We have also tested the reasonableness of the results based on both a logical review of the revenue and expense items using business operating parameters, and on a comparison to historical results. Based on our analyses, we conclude that these revenue lag days and expense lead days are reasonable and calculated properly.

Detailed Findings

The revenue lag and expense lead calculations developed in this study are overall quite similar when compared to the 2009 calculations, indicating there have been no significant changes in the operating and regulatory environments that would materially affect the overall calculation of the cash working capital requirements. The calculated overall revenue lag is 38.01 days versus 38.62 days in the prior study, reflecting a stable revenue lag.

On the expense side there appears to be more variability in the calculated expense leads among

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individual expense line items. However, the overall expense lead of 21.61 days is fairly consistent with the 19.48 days in the prior study.

Among individual expense items, the expense lead for Taxes Other than Income was considerably different. The current study calculated this lead at 164.74 days, versus 83.21 days previously. This is driven by the 2014 tax reform, which significantly reduced the amount of franchise tax paid. This tax, which was historically paid soon after each billing cycle, had previously offset the long lead of property taxes. Since this account has dwindled by over $100 million from the 2009 study, there is no item to balance the long lead of property taxes.

As previously noted, the expense lead for other O&M not separately analyzed increased to 39.98 days, due to stricter adherence to DEC's 45-day payment terms.

The cash working capital requirement is currently calculated at $223.6 million. When factoring in NC Sales Tax, this amount increases to $230.3 million, representing an approximately $25.3 million increase from the previous study. This appears to be predominantly driven by a higher daily requirement, representing normal growth and inflation from the time of the previous study. Items like Other Income Taxes had a minimizing effect by expanding the Requirement Lead Days, but normal growth and inflation still requires a larger Cash Working Capital Requirement.

Appendix

Duke Energy Carolinas, LLC				
Cash Working Capital Requirements for NC Retail Operations				
Revenue and Expense Lead-Lag Summary				
For the 12 Months Ended December 31, 2017				
		NC Retail	Lead	
Line		Jurisdictional	\Lag	Weighted
No.		Amount	Days	Amount
1	Total Revenue Lag	(4,979,947,688)	38.01	(189,265,107,983)
2	Operation and Maintenance Expense	2,554,282,983	26.80	68,446,810,371
3	Depreciation and Amortization	781,791,508	0.00	0
4	Taxes Other Than Income Taxes	185,453,667	164.74	30,552,113,886
5	Interest on Customer Deposits	7,471,530	218.40	1,631,782,152
6	Income Taxes	418,227,583	16.76	7,010,730,021
7	Investment of Tax Credit	(3,551,995)	0.00	0
8	Net Operating Income	1,036,272,412	0.00	0
10	**Total Requirements**	4,979,947,688	21.61	107,641,436,430
11	Revenue Lag Days		38.01	
12	Requirement Lead Days		21.61	
13	**Net Lag Days**		16.39	
14	Daily Requirements			13,643,692
15	Cash Working Capital Requirements			223,626,497
16	Working Capital Related to NC Sales Tax			6,694,345
17	Total Cash Working Capital Requirements			230,320,842

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	Duke Energy Carolinas, LLC							
	Cash Working Capital Requirements for NC Retail Operations							
	Revenue and Expense Lead-Lag Summary							
	For the 12 Months Ended December 31, 2017							
					Total YTD	NC Retail	Lead	
Line					Dec	Jurisdictional	\ Lag	Weighted
No.	Total Utility Operating Revenue and Expense Line Description		Account		2017	Amount	Days	Amount
1	**OPERATING REVENUES:**							
2								
3	CBIS & MBAS Billing System							
4	Service Lag						15.21	
5	Billing Lag							
6	Total Retail Sales				(6,190,731,044)			
7	Cycle & Non-Cycle Read Customers				(6,153,742,033)			
8	Hourly Pricing (HP, HPX, HPF)				(17,239,443)			
9	Parallel Generation (PG)				(1,481,690)			
10	Governmental Lighting (PL)				(36,989,011)			
11	Total Billing Lag				(6,209,452,177)	(4,601,261,829)	1.74	
12								
13	Unbilled Revenue		0440.99, 0442.19, 0442.29, 0444.99		(20,628,546)	(14,921,709)		
14								
15	Collection Lag						22.63	
16								
17	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)				(6,230,080,723)	(4,616,183,538)	39.58	(182,700,850,795)
18								
19	BPM Billing System							
20	Total Revenue Lag Sales for Resale BPM				(555,060,872)	(36,446,619)	35.44	(1,291,668,177)
21								
22	Total Miscellaneous Rider Revenue		0456500 - 0456570		(287,755,803)	(216,904,840)	0.00	-
23								
24	Provisions For Rate Refunds		0449100		13,034,471	13,034,471	39.58	515,882,638
25								
26	Forfeited Discounts		0450100, 0450200		(18,368,585)	(14,012,496)	70.00	(980,874,720)
27								
28	Miscellaneous Revenues		0451100, 0451200		(10,801,723)	(8,240,106)	76.00	(626,248,056)
29								
30	Rent - Joint Use		0454004		(133,305)	(97,798)	45.21	(4,421,448)
31								
32	Rent from Electric Property							
33	Extra Facilities - Depreciation		0454100		(7,930,359)	(6,150,488)	0.00	-
34	Extra Facilities - Other		0454100		(23,215,514)	(18,005,078)	39.58	(712,610,979)
35	Interconnection Cogeneration		0454110		(2,064,812)	(1,601,391)	39.58	(63,380,387)
36	Total Acct 0454.1 (Ln 33 through Ln 35)				(33,210,686)	(25,756,957)		(775,991,366)
37								
38	Pole & Line Attachments		0454200		(33,120,695)	(25,735,528)	143.39	(3,690,217,290)
39								
40	0454300 - Tower Lease Revenues		0454300		(13,042,761)	(6,826,747)	(93.97)	641,499,431
41	0454400 - Other Electric Rents		0454400		(4,180,486)	(2,861,893)	45.21	(129,386,183)
42	0454500 - Leased Facilities Fee - Catawba (NCWHL)		0454500		(564,717)	0		
43	0454500 - Leased Facilities Fee - Catawba (SCWHL)		0454500		(112,069)	0		
44	0454510 - Return and Dep - Catawba Gen Plt		0454510		(14,020,857)	(9,598,451)	(15.21)	145,992,432
45	0454600 - Lease Revenue - CERT		0454600		0	0		
46	0454601 -Other Miscellaneous Revenue - Timber Sales		0454720		(32,619)	(22,330)	0.00	-
47	Total Acct 454 (L30 + L36 through L46)				(98,418,195)	(70,899,703)		(3,812,524,422)
48								
49	Subsidiary Cost of Capital		0455000		0	0	0.00	-
50								

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Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
51	Other Electric Revenues	0456100	(2,779)	(1,904)	0.00	-
52						
53	Distribution Charge - Network					
54	North Carolina	0456102	(2,583,893)	0	0.00	-
55	South Carolina	0456102	(1,547,711)	0	0.00	-
56	Total Acct 456.102 (L54 + L55)		(4,131,604)	0		-
57						
58	Metering - Network NCWHL	0456103	(18,340)	0	0.00	
59	Metering - Network SCWHL	0456103	(48,823)	0	0.00	
60	Comp For Serv To Other (Catawba)	0456300	(18,226,583)	(12,477,622)	(15.21)	189,784,631
61						
62	Other Electric Revenues	0456610	(1,601,984)	(1,096,692)	36.03	(39,513,813)
63						
64	Gross Up-Contr in Aid of Const	0456630	(1,540,650)	(1,137,770)	(15.21)	17,305,482
65						
66	Deferred Dsm Costs - NC	0456640	(170,147)	(170,147)	0.00	-
67	Deferred Dsm Costs - SC	0456650	0	0	0.00	-
68	Other Revenue Affiliate	0456949	(13,703,408)	(9,381,130)	40.21	(377,215,253)
69	Other Transmission Revenues	0456111	(2,090,331)	(2,090,331)	0.00	-
70						
71	Revenues from Transmission of Electricity to Others					
72	Other Variable Revenues-Reg	0456001	(153,765)	(101,448)	40.41	(4,099,514)
73	I/C Joint Disp - Trans NW Rev	0456016	(55,075)	(36,336)	40.41	(1,468,338)
74	Transmission Study Revenue	0456050	(11,401)	(7,522)	40.41	(303,964)
75	Trans of Elec to Others-NCWHL		(56,918,760)	0	40.41	-
76	Trans of Elec to Others-SCWHL		(25,311,998)	0	40.41	-
77	Trans Charge PTP-Non-Firm-BPM & WO Sharing		(3,793,954)	(3,793,954)	40.41	(153,313,681)
78	Total Revenues from Transm of Electricity to Others (L72 through L77)		(86,244,953)	(3,939,260)		(159,185,497)
79	Total Acct 456 (L51 + L56 + L58 through L69 + L78)		(127,779,602)	(30,294,857)		(368,824,450)
80	**Utility Oper Revenues (L17 + L20+ L22 +L24 + L26 + L47 +L49 + L79)**		(7,315,231,033)	(4,979,947,688)	38.01	(189,265,107,983)
81	ELECTRIC OPERATING REVENUE		(7,315,231,033)	(4,979,947,688)		
84						
85	**OPERATION AND MAINTENANCE EXPENSE:**					
86						
87	**Fuel Used in Electric Generation**					
88						
89	Fossil					
90	Beneficial Reuse - Coal Ash	0501007	120,481,185	79,423,035	20.79	1,651,204,908
91	Contra Fuel Exp BR Ash - SC	0501008	(28,538,740)	-		-
92	Contra Fuel Exp BR Ash - WS	0501009	0	-		-
93	Coal Consumed Fossil Steam	0501110	747,365,798	492,674,936	20.79	10,242,711,930
94	Oil Consumed - Fossil Steam	0501310	5,771,526	3,804,678	10.00	38,046,780
95	Oil Light-Off - Fossil Steam	0501330	7,542,632	4,972,218	10.00	49,722,180
96	Emission Allowances	0509000	5,450	3,596	0.00	-
97	NOx Emission Expense	0509210	(30)	(20)	0.00	-
98	RECS Consumption Expense	0509213	13,635,107	12,630,118	0.00	-
99	Commissions/Brokerage Expense	0557450	21,600	14,251	26.80	381,880
100	EA & Coal Broker Fees	0557451	4,625	3,051	0.00	-
101						
102	Nuclear					
103	Burnup of Owned Fuel	0518100	307,787,905	202,898,483	0.00	-
104	Canister Design Expense	0518620	338,622	223,409	0.00	-
105						

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Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
106	Other Production					
107	Natural Gas	0547100	23,821,600	15,703,562	38.00	596,735,356
108	Natural Gas - CC	0547101	259,880,254	171,317,028	38.00	6,510,047,064
109	Biogas Expense	0547106	996,324	656,792	38.00	24,958,096
110	REC Biogas Contra Expense	0547107	(404,508)	(266,658)	38.00	(10,133,004)
111	IC Gas Purchases	0547124	11,387,785	7,507,002	38.00	285,266,076
112	Oil	0547200	3,711,900	2,446,941	38.00	92,983,758
113	**Fuel Used in Elec Gen (HFM Greenbook I/S)**	F_FUEL_USED_ELEC_GEN	**1,473,809,036**	**994,012,423**	**19.60**	**19,481,925,024**
114						
115	**Purchased Power**	0555XXX	**348,770,283**	**231,120,265**	**39.00**	**9,013,690,335**
116						
117	**Total Other O&M Excluding Fuel and Purchased Power**					
118						
119	Nuclear Fees in Acct 524	0524000	51,817,979	34,187,378	(34.15)	(1,167,498,959)
120						
121	Labor					
122	Payroll Net of Deductions		427,972,177	292,982,787	40.43	11,845,294,078
123	Payroll Deductions		278,369,096	190,566,952	9.78	1,863,744,791
124	Total Labor (Ln 149+150)		706,341,273	483,549,739	28.35	13,709,038,869
125						
126	Pension and Benefits	0926XXX	130,547,562	89,254,582	12.36	1,103,186,634
127						
128	Regulatory Commission Expense	0928000	11,375,477	7,901,083	72.31	571,327,312
129						
130	Property Insurance	0924XXX	10,862,755	7,383,136	(212.16)	(1,566,406,134)
131						
132	Injuries & Damages - Workman's Compensation	0925980	7,400,514	5,171,934	(145.50)	(752,516,397)
133						
134	Remaining Other Oper & Maint Expense		1,001,879,049	701,702,443	39.98	28,054,063,688
135						
136	Total O&M Excl. Fuel and Purch. Power		1,920,224,610	1,329,150,295	30.06	39,951,195,012
137						
138	**Total Operation and Maintenance Expense (L113 + L115 + L136)**		**3,742,803,929**	**2,554,282,983**	**26.80**	**68,446,810,371**
139						
140	Total Depreciation & Amortization & Property Loss		1,134,170,294	781,791,508	0.00	-
141						
142	Taxes Other Than Income Taxes					
143	Payroll Taxes		46,582,702	31,853,838	9.33	297,196,309
144	North Carolina Property Tax		106,165,393	78,521,714	186.50	14,644,299,661
145	South Carolina Property Tax		132,014,761	79,966,798	196.50	15,713,475,807
146	Other Non-Income Taxes		(7,441,533)	(4,888,683)	21.04	(102,857,890)
147	Taxes Other Than Income Taxes		277,321,324	185,453,667	164.74	30,552,113,886
148						
149	Total Interest on Customer Deposits		8,499,601	7,471,530	218.40	1,631,782,152
150						
151	Net Income Taxes					
152	Federal Income Tax		212,429,582	143,446,030	44.75	6,419,209,843
153	State Income Tax		19,575,054	13,218,328	44.75	591,520,178
154	Federal Income Tax - Deferred		352,901,899	238,872,663	0.00	-
155	State Income Tax - Deferred		33,602,511	22,690,562	0.00	-
156	Net Income Taxes		618,509,046	418,227,583	16.76	7,010,730,021
157						

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Line No.	Total Utility Operating Revenue and Expense Line Description		Account		Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
158	Investment of Tax Credit Adj Net		04114XX		(5,298,340)	(3,551,995)	0.00	-
159								
160	**Total Utility Operating Expenses (L138 + L140 + L147 + L149 + L151 + L153)**				5,776,005,853	3,943,675,276	27.29	107,641,436,430
161								
162	Net Utility Operating Income				1,539,225,180	1,036,272,412	0.00	-
163								
164	Total Requirements (Ln 269+273)				7,315,231,033	4,979,947,688		107,641,436,430
165								
166								
167	Cash Working Capital Related to NC Sales Tax				6,694,345			

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Duke Energy Carolinas, LLC
E-7, Sub 1146 – Rate Case Requirement

Detailed accounting of Duke Energy Carolinas, LLC's ("DEC") Cost of Removal Reserve for its steam assets and how DEC is utilizing this Cost of Removal Reserve

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Cost of removal, or "COR," represents the cost of demolishing, dismantling, tearing down or otherwise removing retired electric plant assets. For Steam Production assets, cost of removal can be related to interim retirements or final retirements. Interim cost of removal represents costs incurred related to retirements that occur prior to the final retirement of the generation plant (i.e., replacing a pump during the life of the plant). Final cost of removal represents costs incurred at the end of the production plant's life (i.e. demolishing the power house building after the plant has been retired). Per FERC guidance, cost of removal is tracked separately from legal asset retirement obligations.[1] For example, cost of removal for the Steam Production function does not include an accrual for costs associated with ash basin closure that are recorded as an asset retirement obligation.

DEC accrues for COR as part of depreciation expense. Cost of removal assumptions are reviewed and analyzed through the process of preparing a depreciation study and thus estimates for COR are a component of DEC's depreciation rates. Assumptions for interim cost of removal are primarily based on historical interim retirement and net salvage data as well as informed judgment related to the specific depreciation groups. Assumptions related to final cost of removal are primarily based on decommissioning studies performed by outside consultants. The depreciation rates currently in place were approved during the last rate case.

DEC follows FERC guidance related to accounting for cost of removal. Cost of removal is accrued monthly for assets that are currently in-service. Each month, the portion of depreciation expense that is related to cost of removal accrues as a credit to the cost of removal reserve, which is recorded within FERC Account 108 – Accumulated Depreciation. When an asset is removed from service, any costs incurred to remove the asset are charged against (i.e., debited to) the accrued COR reserve. At the time of a depreciation study, cost of removal estimates are revisited for assets in-service at the time of the study, and cost of removal rates are adjusted based on the cost of removal liability balance at the time of the study. Cost of removal is tracked by function, and reserves accrued for a given function are intended to

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[1] *Cost of removal* means the cost of demolishing, dismantling, tearing down or otherwise removing electric plant, including the cost of transportation and handling incidental thereto. 18 C.F.R. §101, Definitions. 10. By contrast, an *asset retirement obligation* represents a liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel. *See* 18 C.F.R. §101, General Instruction 25. By definition, "[c]ost of removal does not include the cost of removal activities associated with asset retirement obligations that are capitalized as part of the tangible long-lived assets that give rise to the obligation." 18 C.F.R. §101, Definitions. 10.

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cover removal costs for that function. For example, cost of removal accrued for Steam Production will only be used to cover removal activities associated with Steam Production assets, unless DEC is specifically approved to treat otherwise.

See below for a summary of the cost of removal reserve activity for Steam Production from December 31, 2016 through June 30, 2019.

Duke Energy Carolinas
Detail of Cost of Removal Reserve Activity
January 1, 2017 - June 30, 2019
Amounts in $

	Beginning Balance December 31, 2016	COR Expense Accrued	Cost of Removal	Other*	Ending Balance June 30, 2019
Steam Production Plant	308,076,978	53,461,002	(62,055,334)	(344,182)	299,138,464

Note: The amounts above exclude Retirement Work in Process (RWIP)

* Other activity primarily relates to transfer activity. If an asset is transferred to another entity or if an asset is transferred to another function, the COR accrued related to the asset will also transfer.

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Duke Energy Carolinas, LLC
Docket No. E-7, Sub 1214
Updated Cash Working Capital for NC Retail Operations - Lead Lag Summary
For the Test Year ended December 31, 2018

No.	Description	Actual Annual Amount [A]	Lead (Lag) Days [B]	Weighted Amount [C]
	Calculation of NC Retail Amount:			
1	Total Revenue Lag		40.09	
2				
3	Operation and Maintenance Expense	2,559,661,028	30.71	78,598,071,979
4	Depreciation and Amortization	838,804,844	0.00	0
5	Taxes Other Than Income Taxes	194,680,961	168.11	32,727,032,211
6	Interest on Customer Deposits	7,129,673	218.40	1,557,120,627
7	Income Taxes	224,997,489	0.48	107,265,513
8	Investment of Tax Credit	(3,525,573)	0.00	0
9	Net Operating Income	1,082,335,768	24.97	27,025,316,831
10	Total Requirements (Sum L3 through L9)	4,904,084,190	28.55	140,014,807,161
11				
12	Revenue Lag Days (L1)		40.09	
13	Requirements Lead Days (-L10)		(28.55)	
14	Net Lag Days (L12 + L13)		11.54	
15	Daily Requirements (Line 10, Col. A divided by 365)			13,435,847
16				
17	Estimated Cash Working Capital Requirements (L14 x L15)			155,063,806
18	Add: Cash Working Capital Related to NC Sales Tax			6,203,981
19	Total Cash Working Capital Requirements (L17 + L18)			161,267,787
20				
21	**Calculation of Total Company and Jurisdictional Amounts:**			
22	NC Retail Factor "All - Rate Base x CWC" Allocation Factor			68.1442%
23				
24	Total Company Cash Working Capital Requirements (L19 / L22)			$ 236,656,522

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Duke Energy Carolinas, LLC

Lead-Lag Study

January 2020

Building a better working world

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Feb 14 2020

Ernst & Young LLP
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Charlotte, NC 28202

Tel: +1 704 372 6300
ey.com

January 8, 2020

Abbe Greenfield
Rate Case Planning & Execution, Duke Energy Carolinas, LLC
526 South Church Street
Charlotte, NC 28202

Mrs. Greenfield:

We have completed our procedures with respect to analyzing a detailed lead-lag study for Duke Energy Carolinas, LLC ("the Company" or "DEC") focused on retail operations in the state of North Carolina. Our procedures were performed in accordance with our Statement of Work, dated April 19, 2018. Our report consists of three parts. We summarize our scope, approach and findings in a narrative executive summary; we present our detailed findings in a schedule that provides the lag and lead days by revenue and expense component used by DEC in its cost of service filings; and we provide an appendix that provides the company's summary calculations with a reference to 19 underlying detail schedules.

The information provided in this report is intended to be used to support the Company's request for a cash working capital allowance to be included in the Company's requested rate base to be authorized by the North Carolina Utility Commission. The report is not intended to be, and should not be, used without our prior written consent by any other party or for any other purpose. Our calculations relied on underlying accounting information provided by the Company. We did not audit that underlying accounting information.

We value the opportunity to work with you and appreciate the cooperation and assistance provided. We would be pleased to discuss any aspect of our work or this report with you or other members of management at your convenience. If you have questions, please call Jake Van Reen at (617) 375-2446.

Thank you,

Jake Van Reen

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Executive Summary

1.1. Organization of Report

This report is composed of three parts: Executive Summary, Detailed Findings, and Appendix.

The Executive Summary provides background on the engagement, the purpose and scope of the lead-lag study, the standards applied and the relation to previous studies, and a discussion of key findings.

The Detailed Findings are provided in a DEC Lead-Lag Summary schedule contained within E-1 Item 14. This schedule provides the lag and lead days by revenue and expense component used by the Company in its cost of service filings. The summary was agreed to the underlying supporting schedules.

1.2. Background

Duke Energy Company, LLC ("Duke") engaged Ernst & Young ("EY") to support the preparation of a lead-lag study for Duke's retail operations in the state of North Carolina. The study will be used to support the Company's request for a cash working capital allowance to be included in the requested rate base. This report presents the methodology and approach used in the study and the results covering the twelve-month period ending December 31, 2017, subject to known changes.

The Company last presented a lead-lag study to the North Carolina Utility Commission ("NCUC" or the "Commission") for the twelve-month period ending December 31, 2009. This report presents the lead-lag study in the same general format and applies the same methodologies where applicable. Since that time, there are assumed to have been no significant changes in the operating and regulatory environments that would materially affect the calculation of the cash working capital requirements. To confirm this assumption, EY interviewed Duke personnel and a contractor responsible for compiling the study. EY also analyzed certain of the Company's financial statements and riders to DEC's regulatory requirements for the same purpose.

Changes from report previously filed on May 22, 2019

Total Cash Working Capital Requirements decreased by $8.2M as compared to the previously

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filed report.

Cash Working Capital Requirements decreased due to the following adjustments:

- Payroll deductions and payroll taxes – Within payroll deductions and payroll taxes, amounts related to incentive compensation were identified. The service period related to these amounts was adjusted to correspond to the service period for incentive compensation. Adjustments to payroll deductions result in a ($10.6M) decrease, while adjustments to payroll taxes result in a ($3.7M) decrease.
- Regulatory commission expense – Regulatory commission expense related to the South Carolina PSC was included in the original study. Removing this item resulting in a ($379K) decrease.

Cash Working Capital Requirements increased due to the following adjustments:

- Pension and benefits – For account 1B410 (Undergrad Tuition Reimbursement), the payment date was adjusted for a January payment. This adjustment results in a $37K increase.
- Property insurance – Line items related to account 0924980 were not calculated correctly in the original study due to an erroneous relative cell reference, resulting in a $5.3M increase.
- Other O&M expense – Other O&M expense in the final Cost of Service decreased by $1.5M from the Cost of Service version used for the original study. Additionally, uncollectible accounts were broken out separately and a zero-day expense lead was applied consistent with NCUC practice. These two adjustments result in a net increase of $1.1M to cash working capital requirements.

1.3. Cash Working Capital

1.3.1. Purpose of lead-lag study

The lead-lag study is designed to measure the average amount of capital, over and above the investments in plant, and other separately identified rate base items, provided by investors to bridge the gap between the time expenditures are required to provide service and the time collections of revenues are received for the service. This quantity is referred to as cash working capital. Cash working capital is more comprehensive than simply financing the lag between

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Company payments and receipts, as investor capital is required to finance the lag in the recovery of the entire cost of service, including depreciation and cost of capital.

1.3.2. Cash working capital requirement

A requirement for cash working capital represents the amount necessary to provide the utility with an opportunity to appropriately earn an authorized return on all capital invested in utility operations. Unless all capital supplied by investors has that opportunity, investors will not be fully compensated for the capital supplied and the objective of the cash working capital requirement will not be met. Consequently, the key test of the adequacy of the cash working capital requirement should be whether the inclusion of such an amount when added to net utility plant and other items includible in the rate base will produce a fair representation of the capital on which there should be an opportunity to earn a return.

1.3.3. Lead-lag study methodology

To the extent applicable, this study tracks the methodology used in the previous rate filings of the Company and decisions of the NCUC.

The lead-lag study measures the difference in time frames between: (1) when service is rendered and the revenue for that service is received ("revenue lag"); and (2) when the costs of providing service are incurred (including costs of fuel and purchased power, labor, materials, services, etc.) and the time for which those costs are paid ("expense lead"). The difference between these lag periods is expressed in terms of days. The calculated number of days multiplied by the average daily operating revenues or cost of service produces the cash working capital required by the Company.

To fully identify cash working capital requirements, there are additions and deductions to the amount calculated in the lead-lag study. This is done to adjust for items not accounted for in rate base. For example, we must add operational cash requirements and add or deduct any other requirements for, or sources of, cash working capital (such as prepayments, reserves, and items capitalized prior to payment). In previous rate case proceedings, these adjustments have been considered separately from the lead-lag study, so they are not considered in this report.

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1.3.4. Results of lead-lag study for DEC retail electric operations

The following section provides a summary of the most significant revenue lags and expense leads calculated. Additional detailed identification of the calculated revenue lags and expense leads is included in the attached schedule entitled E-1 Item 14 ("the summary schedule").

1.4. Revenue Lag

The revenue lag measures the time between service delivery to customers and the collection of revenue for service from customers. For the year ending December 31, 2017, approximately 99% of North Carolina retail jurisdictional revenue was received from cycle billed customers (customers billed on a periodic basis) and the large customer billing group, DEC's Customer Billing Information System (CBIS) and Lodestar Billing Expert systems, respectively.

The revenue lag for these services is the sum of three components: (i) service lag, (ii) billing lag and (iii) collection lag.

The first component is service lag. The Company reads the meters on a monthly basis; therefore the average time between meter reads is 30.42 days (365 days in a year divided by 12 monthly meter reads). Dividing by two provides the midpoint in time, or the average time between when service is provided and the meter read, for a service lag of 15.21 days. (See summary schedule line 4.)

The second component of the total revenue lag is billing lag, the time from the meter reading to when the customer is billed and the bill is posted in the Company's accounts receivable system. Most customers are billed the next business day after the meter is read. Taking into account weekends and holidays, the calculation of the total billing lag is 1.74 days. (See summary schedule line 11.) This amount differs from the previous study, which deemed the billing lag to be at approximately half a day, as the previous study did not account for weekends and holidays.

The third component of the total revenue lag is the collection lag, the period from the billing date to the time the customer pays their bill (i.e., the date cash payments are credited on the accounts receivable records). This component of the revenue lag is measured by dividing average daily accounts receivable (based on a thirteen-month average) by average daily sales.

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Collection policies for retail operations in North Carolina are governed by NCUC rules. We calculated the collection lag to be 22.63 days. (See summary schedule line 15.)

Adding these three components together produced a total lag of 39.58 days in the collection of revenues for services provided to cycle-read and large customer billing group customers on electric delivery rate schedules. (See summary schedule line 17.)

EY did not factor in the potential impact of float. The Company experiences two float periods - the time from when funds are received from customers until the funds clear the banks, and the time between when the Company sends a check to pay for services and when those checks are deposited. In the first instance, the Company's cash requirements are increased by the float (i.e. funds are not actually available until after the deposits clear). However, in the second instance, the Company's cash requirements are reduced by the float. Given the relative levels of electronic funds transfers in the Company's payments versus in its receipts, we are confident that the float for revenue is larger than the float for expense. Accordingly, excluding float in this instance is a conservative assumption that would not harm the ratepayer.

In addition to the above, the Company records a variety of additional and miscellaneous revenues which are also applicable to the North Carolina retail jurisdiction. These include intersystem sales for resale, miscellaneous riders (unbilled fuel and deferred revenue), provisions for refunds, forfeited discounts, rental income, pole and line attachment, and revenue from the transmission of electricity to others. To calculate the overall average revenue lag, we calculated the revenue lags for each of the additional and miscellaneous revenues. The total revenue lag for DEC is 38.01 days. (See summary schedule line 80.)

1.5. Expense lead

There are several major categories of expense including:

- O&M Fuel
- O&M Purchased Power
- Labor and Benefits
- Other specifically identified O&M
- Other O&M sampled

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- Depreciation and Amortization
- Taxes other than Income
- Interest on Customer Deposits
- Income Taxes
- Net Operating Income

Each of the above are described in more detail below.

1.5.1. O&M Fuel

O&M Fuel costs consist of coal, oil, and natural gas purchases. Fuel is the largest cost category, accounting for approximately 20% of the cost of service for the year ending December 31, 2017. Coal costs include two major components: coal commodity purchases and coal transportation costs. The cost of coal purchases and transportation are inventoried and, by NCUC precedent, coal fuel inventories are included in rate base. However, the cash working capital requirement must recognize the cash available to the Company stemming from the time between receipt of coal and the subsequent payment of the fuel or transportation invoice.

DEC receives thousands of coal deliveries at its coal generating stations each year. DEC employs the following coal payment terms: (i) contract deliveries made between the 1st and 15th of the current month are paid by the 30th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days); (ii) contract deliveries made between the 1st and 15th of the current month are paid by the 15th of the following month or contract deliveries made between the 16th and 31st of the current month are paid by the 30th of the following month (37.5 days); (iii) contract deliveries made between the 1st and 31st of the current month are paid by the 30th of the following month (45 days); (iv) contract deliveries made between the 1st and 15th of the current month are paid by the 25th of the current month or contract deliveries made between the 16th and 31st of the current month are paid by the 10th of the following month (17.5 days); (v) contract deliveries made between the 1st and 31st of the current month are paid by the 20th of the following month (35 days); and (vi) contract deliveries paid 10 days after ship date (10 days). Vendor contracts require DEC payments to be received by the vendor by the noted due date.

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DEC employs the following vendor coal transportation contract terms: (i) coal freight payments 15 days after the ship date (15 days); (ii) coal freight received between the 1st and 15th of the current month are paid by the 30th of the current month or coal freight received between the 16th and 31st of the current month are paid by the 15th of the following month (22.5 days). The weighted average coal and coal freight expense lead is 20.79 days. (See summary schedule line 93.)

Nuclear fees have a calculated expense lead of (34.15) days. (See summary schedule line 119.)

Small amounts of oil and natural gas are also used as a fuel for generation. Unlike coal or oil, natural gas is not stored and inventoried, rather it is purchased as it is used to generate electricity. Therefore, the expense lag for natural gas is computed conventionally as the difference between the service period and the date of payment. Since Duke is not storing natural gas to be used for generation, the service period is considered to be the mid-point of the billing period from the gas supplier, and the payment date is simply the date of payment. We calculated the natural gas invoices and their computed expense leads as 38.00 days. (See summary schedule line 107.)

1.5.2. O&M Purchased Power

DEC provided listings of all transactions for each of the purchased power accounts for our analysis. We weighted the individual invoices by dollar amount, resulting in an overall expense lead of 39.00 days. (See summary schedule line 115.)

1.5.3. O&M Labor and Benefits

Labor and benefits comprised approximately 12% of the cost of service for the year ending December 31, 2017. Labor costs fall into three categories: net payroll, deductions from payroll, and taxes. In turn, the Company's payroll consists of two primary categories, semi-monthly payroll and bi-weekly payroll, with lesser amounts of incentive pay. We identified each pay period and the payment dates corresponding to that pay period. Similarly, for payroll related deductions we identified when the payments were made for each deduction type corresponding to each pay period, including identifying the deductions related to incentive compensation. We performed similar analyses on taxes, looking at pay periods the taxes applied to and when the tax payments were made, including identifying the taxes related to incentive compensation.

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1.5.4. Other Specifically Identified O&M

Other specifically identified O&M categories include the following accounts:

- Uncollectible accounts
- Regulatory expenses
- Insurance expenses
- Injuries and damages – workers compensation

Uncollectible accounts expenses result from the timing of the write-off of customer accounts receivable as uncollectible. By NCUC practice, these expenses are valued at zero days expense lead. (See summary schedule line 134.)

We calculated expense lead days for regulatory expenses, insurance expenses and injuries and damages expenses by analyzing service periods, payment amounts and payment patterns. Insurance expenses and injuries and damages are payments for insurance policies. By their nature, insurance policies are paid prior to the service period for coverage; both have negative expense leads. (See summary schedule lines 130 and 132.)

1.5.5. Other O&M Sampled

To determine the expense lead for other O&M not specifically analyzed (summary schedule line 136), the Company provided EY with a listing of cash disbursements for the twelve-month period ending December 31, 2017. We removed records for capital costs, non-electric O&M costs, and any costs already analyzed, resulting in a sample population consisting of $757,657,609 and 38,262 rolled vouchers (Note: there were over 510,000 records, but multiple disbursements were made on the same voucher; since the voucher was the unit sampled, the records were rolled up to the voucher level). From that population, a stratified random sample in nine strata, based on the invoice dollar amount, was selected (274 total selections) for sample testing. For each item sampled, the supporting documentation was obtained and analyzed. For purposes of the analysis, service period information was either provided by Duke based on the supporting documentation or, in instances where the service period was not available, the invoice date was provided. The paid dates utilized in the analysis were taken from the Company's payables ledger.

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The estimated weighted average expense lead calculated from the sample was 39.98 days, plus or minus 5.85 days with 90% confidence. This contrasts to the 25.72 days calculated for the other O&M sample from the previous lead-lag study. When asked about the increase in days, the client informed us that Duke has 45-day payment terms, and has been following these more closely than previously. EY used statisticians to sample the Other O&M population.

In addition, approximately 2% of the other O&M were employee expenses. These were included in our sample, and for large dollar amounts the service period and payment date were provided. For the remainder, we calculated the average lead lag days based on the credit card payment dates; this made up 63% of the sample. All credit cards have the same cut off dates for service periods and the same payment dates. As a result, these were not sampled. Rather the expense lead was calculated as the average time from the midpoint of the service period to the payment date.

1.5.6. Depreciation and Amortization

Expenses for depreciation and amortization are the result of prior cash transactions that are not initially charged to expense. A zero lag is applied because the expense is deducted from rate base when the expense is recorded. By way of example, investors supply cash for capital investments such as plant assets. A cash transaction occurs when a plant asset is acquired. The plant asset is included in rate base and the cash investment earns a return until depreciation expense is recorded. When depreciation expense is recorded, the amount of the expense is removed from rate base and the expense becomes recoverable in cost of service. However, the cash is not recovered until revenues are collected (e.g., after the revenue lag). Thus, depreciation expense is included in the lead-lag study with a zero-expense lead to provide a return for the period from when the depreciation expense is booked and removed from rate base until it is recovered from revenues. (See summary schedule line 142.)

1.5.7. Taxes Other than Income

Expense leads for taxes other than income taxes consider the timing between when the taxes are assessed, and the related service period. Some taxes are assessed and paid prior to the start of the service period and others are paid after a significant portion of the service period has occurred. Overall the average expense lead on taxes other than income for the period

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ending December 31, 2017 was 171.93 days. (See summary schedule line 149.) Per the 2009 lead-lag study, the average expense lead on taxes other than income was 83.21. The increase in the number of lead lag days is the result of tax reform occurring in 2014, which significantly reduced the franchise tax (historically paid soon after each billing cycle). This had previously offset the impact of property taxes, which are paid nearly a year after the service period begins. Additionally, there was a considerable increase in the level of property taxes between 2009 and 2017.

1.5.8. Interest on Customer Deposits

Interest is credited to customers who are required to maintain deposits, and the interest is paid either when the deposit is returned or at periodic intervals. The expense lead on customer deposits is 218.40 days. (See summary schedule line 151.)

1.5.9. Income Taxes

Income taxes has two major components, current and deferred income taxes. In turn, current income taxes include taxes for the current year and taxes for prior periods. The expense lead for current income taxes for the current year is the result of the statutory payment dates. Similar to the rationale for depreciation expense, the deferred tax expense lead is zero days because net deferred tax liabilities are deducted from rate base when the expense is recorded. The expense lead on Net Income Taxes is 16.76 days. (See summary schedule line 158.)

1.5.10. Net Operating Income

Net operating income is the return on invested capital, just as depreciation expense is a return on invested capital. Like depreciation expense, a zero lag was assigned to net operating income in recognition of the fact that the return is earned when the service is provided. Because the return is earned when the service is provided, it would be inappropriate to consider subsequent below the line treatment of net operating income. Therefore we did not further analyze the subsequent use of net operating income for interest, dividends or reinvestment.

1.5.11. Cash Working Capital Impacts of Pass Through Items

As noted, to fully identify the cash working capital requirements, to the amount calculated in the lead lag study we must add operational cash requirements and add or deduct any other requirements for or sources of cash working capital. One item the Company has not included

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elsewhere and is therefore considered here is pass through taxes. Pass through taxes are similar to taxes other than income except the payment is due from customers not the company. The primary pass through tax is the North Carolina utility sales tax. The Company collects these pass-through taxes from customers in their bills and pays the tax to the State. The tax is not a Company expense because the Company is merely a conduit of the payments from customers to the state. But, to the extent the Company pays the tax before the funds are received from customers, investors in the Company need to provide the cash to finance the time between payment and recovery. The impact on total DEC cash working capital requirements due to the NC sales pass through tax is $6,694,345. (See summary schedule line 169.)

Conclusion

We have calculated the revenue lag days and expense lead days documented in the schedule described above. We have also tested the reasonableness of the results based on both a logical review of the revenue and expense items using business operating parameters, and on a comparison to historical results. Based on our analyses, we conclude that these revenue lag days and expense lead days are reasonable and calculated properly.

Detailed Findings

The revenue lag and expense lead calculations developed in this study are overall quite similar when compared to the 2009 calculations, indicating there have been no significant changes in the operating and regulatory environments that would materially affect the overall calculation of the cash working capital requirements. The calculated overall revenue lag is 38.01 days versus 38.62 days in the prior study, reflecting a stable revenue lag.

On the expense side there appears to be some variability in the calculated expense leads among individual expense line items. However, the overall expense lead of 22.21 days is fairly consistent with the 19.48 days in the prior study.

Among individual expense items, the expense lead for Taxes Other than Income was considerably different. The current study calculated this lead at 171.93 days, versus 83.21

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days previously. This is driven by the 2014 tax reform, which significantly reduced the amount of franchise tax paid. This tax, which was historically paid soon after each billing cycle, had previously offset the long lead of property taxes. Since this account has decreased by over $100 million from the 2009 study, there are limited transactions to offset the long lead of property taxes.

As previously noted, the expense lead for other O&M not separately analyzed increased to 39.98 days, due to stricter adherence to DEC's 45-day payment terms.

The cash working capital requirement is currently calculated at $215.5 million. When factoring in NC Sales Tax, this amount increases to $222.2 million, representing an approximately $17.2 million increase from the previous study. This appears to be predominantly driven by a higher daily requirement, representing normal growth and inflation from the time of the previous study. Items like Other Income Taxes had a minimizing effect by expanding the Requirement Lead Days, but normal growth and inflation still requires a larger Cash Working Capital Requirement.

Appendix A

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Duke Energy Carolinas, LLC
Cash Working Capital Requirements for NC Retail Operations
Revenue and Expense Lead-Lag Summary
For the Test Year Ended December 31, 2017

Line No.		NC Retail Jurisdictional Amount	Lead \Lag Days	Weighted Amount
1	Total Revenue Lag	(4,979,947,688)	38.01	(189,265,107,983)
2	Operation and Maintenance Expense	2,552,765,002	27.46	70,093,254,867
3	Depreciation and Amortization	781,791,508	0.00	0
4	Taxes Other Than Income Taxes	185,453,667	171.93	31,884,878,468
5	Interest on Customer Deposits	7,471,530	218.40	1,631,782,152
6	Income Taxes	418,227,583	16.76	7,010,730,021
7	Investment of Tax Credit	(3,551,995)	0.00	0
8	Net Operating Income	1,037,790,393	0.00	0
10	Total Requirements	4,979,947,688	22.21	110,620,645,508
11	Revenue Lag Days		38.01	
12	Requirement Lead Days		22.21	
13	Net Lag Days		15.79	
14	Daily Requirements			13,643,692
15	Cash Working Capital Requirements			215,464,281
16	Working Capital Related to NC Sales Tax			6,694,345
17	Total Cash Working Capital Requirements			222,158,626

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DE CAROLINAS, LLC		Duke Energy Carolinas, LLC					
INCOME STATEMENT		Cash Working Capital Requirements for NC Retail Operations					
		Revenue and Expense Lead-Lag Summary					
		For the Test Year Ended December 31, 2017					
Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
	1	OPERATING REVENUES:					
	2						
	3	CBIS & MBAS Billing System					
Calc	4	Service Lag				15.21	
	5	Billing Lag					
	6	Total Retail Sales		(6,190,731,044)			
	7	Cycle & Non-Cycle Read Customers		(6,153,742,033)			
	8	Hourly Pricing (HP, HPX, HPF)		(17,239,443)			
	9	Parallel Generation (PG)		(1,481,690)			
	10	Governmental Lighting (PL)		(36,989,011)			
1	11	Total Billing Lag		(6,209,452,177)	(4,601,261,829)	1.74	
	12						
	13	Unbilled Revenue	0440.99, 0442.19, 0442.29, 0444.99	(20,628,546)	(14,921,709)		
	14						
2	15	Collection Lag				22.63	
	16						
	17	Total Revenue Lag Elec Delivery Rate Schedule (Ln 11 + 17)		(6,230,080,723)	(4,616,183,538)	39.58	(182,700,850,795)
	18						
	19	BPM Billing System					
3	20	Total Revenue Lag Sales for Resale BPM		(555,060,872)	(36,446,619)	35.44	(1,291,668,177)
	21						
	22	Total Miscellaneous Rider Revenue	0456500 - 0456570	(287,755,803)	(216,904,840)	0.00	-
	23						
	24	Provisions For Rate Refunds	0449100	13,034,471	13,034,471	39.58	515,882,638
	25						
	26	Forfeited Discounts	0450100, 0450200	(18,368,585)	(14,012,496)	70.00	(980,874,720)
	27						
	28	Miscellaneous Revenues	0451100, 0451200	(10,801,723)	(8,240,106)	76.00	(626,248,056)
	29						
	30	Rent - Joint Use	0454004	(133,305)	(97,798)	45.21	(4,421,448)
	31						
	32	Rent from Electric Property					
	33	Extra Facilities - Depreciation	0454100	(7,930,359)	(6,150,488)	0.00	-
	34	Extra Facilities - Other	0454100	(23,215,514)	(18,005,078)	39.58	(712,610,979)
	35	Interconnection Cogeneration	0454110	(2,064,812)	(1,601,391)	39.58	(63,380,387)
	36	Total Acct 0454.1 (Ln 33 through Ln 35)		(33,210,686)	(25,756,957)		(775,991,366)
	37						
4	38	Pole & Line Attachments	0454200	(33,120,695)	(25,735,528)	143.39	(3,690,217,290)
	39						
4	40	0454300 - Tower Lease Revenues	0454300	(13,042,761)	(6,826,747)	(93.97)	641,499,431
4	41	0454400 - Other Electric Rents	0454400	(4,180,486)	(2,861,893)	45.21	(129,386,183)
	42	0454500 - Leased Facilities Fee - Catawba (NCWHL)	0454500	(564,717)	0		
	43	0454500 - Leased Facilities Fee - Catawba (SCWHL)	0454500	(112,069)	0		
	44	0454510 - Return and Dep - Catawba Gen Plt	0454510	(14,020,857)	(9,598,451)	(15.21)	145,992,432
	45	0454600 - Lease Revenue - CERT	0454600	0	0		
	46	0454601 -Other Miscellaneous Revenue - Timber Sales	0454720	(32,619)	(22,330)	0.00	-
	47	Total Acct 454 (L30 + L36 through L46)		(98,418,195)	(70,899,703)		(3,812,524,422)
	48						
	49	Subsidiary Cost of Capital	0455000	0	0	0.00	-
	50						
	51	Other Electric Revenues	0456100	(2,779)	(1,904)	0.00	-
	52						

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Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
	53	Distribution Charge - Network					
	54	North Carolina	0456102	(2,583,893)	0	0.00	-
	55	South Carolina	0456102	(1,547,711)	0	0.00	-
	56	Total Acct 456.102 (L54 + L55)		(4,131,604)	0		-
	57						
	58	Metering - Network NCWHL	0456103	(18,340)	0	0.00	
	59	Metering - Network SCWHL	0456103	(48,823)	0	0.00	
	60	Comp For Serv To Other (Catawba)	0456300	(18,226,583)	(12,477,622)	(15.21)	189,784,631
	61						
	62	Other Electric Revenues	0456610	(1,601,984)	(1,096,692)	36.03	(39,513,813)
	63						
	64	Gross Up-Contr in Aid of Const	0456630	(1,540,650)	(1,137,770)	(15.21)	17,305,482
	65						
	66	Deferred Dsm Costs - NC	0456640	(170,147)	(170,147)	0.00	-
	67	Deferred Dsm Costs - SC	0456650	0	0	0.00	-
	68	Other Revenue Affiliate	0456949	(13,703,408)	(9,381,130)	40.21	(377,215,253)
	69	Other Transmission Revenues	0456111	(2,090,331)	(2,090,331)	0.00	-
	70						
	71	Revenues from Transmission of Electricity to Others					
	72	Other Variable Revenues-Reg	0456001	(153,765)	(101,448)	40.41	(4,099,514)
	73	I/C Joint Disp - Trans NW Rev	0456016	(55,075)	(36,336)	40.41	(1,468,338)
	74	Transmission Study Revenue	0456050	(11,401)	(7,522)	40.41	(303,964)
	75	Trans of Elec to Others-NCWHL		(56,918,760)	0	40.41	-
	76	Trans of Elec to Others-SCWHL		(25,311,998)	0	40.41	-
	77	Trans Charge PTP-Non-Firm-BPM & WO Sharing		(3,793,954)	(3,793,954)	40.41	(153,313,681)
	78	Total Revenues from Transm of Electricity to Others (L72 through L77)		(86,244,953)	(3,939,260)		(159,185,497)
	79	Total Acct 456 (L51 + L56 + L58 through L69 + L78)		(127,779,602)	(30,294,857)		(368,824,450)
	80	Utility Oper Revenues (L17 + L20+ L22 +L24 + L26 + L47 +L49 + L79)		(7,315,231,033)	(4,979,947,688)	38.01	(189,265,107,983)
	81	ELECTRIC OPERATING REVENUE		(7,315,231,033)	(4,979,947,688)		
	84						
	85	OPERATION AND MAINTENANCE EXPENSE:					
	86						
	87	Fuel Used in Electric Generation					
	88						
	89	Fossil					
5	90	Beneficial Reuse - Coal Ash	0501007	120,481,185	79,423,035	20.79	1,651,204,908
	91	Contra Fuel Exp BR Ash - SC	0501008	(28,538,740)	-		-
	92	Contra Fuel Exp BR Ash - WS	0501009	0	-		-
5	93	Coal Consumed Fossil Steam	0501110	747,365,798	492,674,936	20.79	10,242,711,930
5	94	Oil Consumed - Fossil Steam	0501310	5,771,526	3,804,678	10.00	38,046,780
5	95	Oil Light-Off - Fossil Steam	0501330	7,542,632	4,972,218	10.00	49,722,180
	96	Emission Allowances	0509000	5,450	3,596	0.00	-
	97	NOx Emission Expense	0509210	(30)	(20)	0.00	-
	98	RECS Consumption Expense	0509213	13,635,107	12,630,118	0.00	-
	99	Commissions/Brokerage Expense	0557450	21,600	14,251	26.80	381,880
	100	EA & Coal Broker Fees	0557451	4,625	3,051	0.00	-
	101						
	102	Nuclear					
	103	Burnup of Owned Fuel	0518100	307,787,905	202,898,483	0.00	-
	104	Canister Design Expense	0518620	338,622	223,409	0.00	-
	105						

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Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
	106	Other Production					
6	107	Natural Gas	0547100	23,821,600	15,703,562	38.00	596,735,356
	108	Natural Gas - CC	0547101	259,880,254	171,317,028	38.00	6,510,047,064
	109	Biogas Expense	0547106	996,324	656,792	38.00	24,958,096
	110	REC Biogas Contra Expense	0547107	(404,508)	(266,658)	38.00	(10,133,004)
	111	IC Gas Purchases	0547124	11,387,785	7,507,002	38.00	285,266,076
	112	Oil	0547200	3,711,900	2,446,941	38.00	92,983,758
	113	Fuel Used in Elec Gen (HFM Greenbook I/S)	F_FUEL_USED_ELEC_GEN	1,473,809,036	994,012,423	19.60	19,481,925,024
	114						
7	115	Purchased Power	0555XXX	348,770,283	231,120,265	39.00	9,013,690,335
	116						
	117	Total Other O&M Excluding Fuel and Purchased Power					
	118						
8	119	Nuclear Fees in Acct 524	0524000	51,817,979	34,187,378	(34.15)	(1,167,498,959)
	120						
	121	Labor					
9	122	Payroll Net of Deductions		427,972,177	292,982,787	40.43	11,845,294,078
9	123	Payroll Deductions		278,369,096	190,566,952	30.13	5,741,782,264
	124	Total Labor (Ln 149+150)		706,341,273	483,549,739	36.37	17,587,076,342
	125						
10	126	Pension and Benefits	0926XXX	130,547,562	89,254,582	12.21	1,089,798,446
	127						
11	128	Regulatory Commission Expense	0928000	11,375,477	7,901,083	89.82	709,705,428
	129						
15	130	Property Insurance	0924XXX	10,862,755	7,383,136	(474.55)	(3,503,667,189)
	131						
17	132	Injuries & Damages - Workman's Compensation	0925980	7,400,514	5,171,934	(145.50)	(752,516,397)
	133						
	134	Uncollectible Accounts	0904000, 0904001	11,758,924	8,970,309	0.00	-
	135						
	136	Remaining Other Oper & Maint Expense		990,120,126	691,214,153	39.98	27,634,741,837
	137						
	138	Total O&M Excl. Fuel and Purch. Power		1,920,224,610	1,327,632,314	31.33	41,597,639,509
	139						
	140	Total Operation and Maintenance Expense (L113 + L115 + L136)		3,742,803,929	2,552,765,002	27.46	70,093,254,867
	141						
	142	Total Depreciation & Amortization & Property Loss		1,134,170,294	781,791,508	0.00	-
	143						

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Support Sch #	Line No.	Total Utility Operating Revenue and Expense Line Description	Account	Total YTD Dec 2017	NC Retail Jurisdictional Amount	Lead \ Lag Days	Weighted Amount
	144	Taxes Other Than Income Taxes					
9	145	Payroll Taxes		46,582,702	31,853,838	51.17	1,629,960,890
13	146	North Carolina Property Tax		106,165,393	78,521,714	186.50	14,644,299,661
13	147	South Carolina Property Tax		132,014,761	79,966,798	196.50	15,713,475,807
13	148	Other Non-Income Taxes		(7,441,533)	(4,888,683)	21.04	(102,857,890)
	149	Taxes Other Than Income Taxes		277,321,324	185,453,667	171.93	31,884,878,468
	150						
16	151	Total Interest on Customer Deposits		8,499,601	7,471,530	218.40	1,631,782,152
	152						
	153	Net Income Taxes					
14	154	Federal Income Tax		212,429,582	143,446,030	44.75	6,419,209,843
14	155	State Income Tax		19,575,054	13,218,328	44.75	591,520,178
	156	Federal Income Tax - Deferred		352,901,899	238,872,663	0.00	-
	157	State Income Tax - Deferred		33,602,511	22,690,562	0.00	-
	158	Net Income Taxes		618,509,046	418,227,583	16.76	7,010,730,021
	159						
	160	Investment of Tax Credit Adj Net	04114XX	(5,298,340)	(3,551,995)	0.00	-
	161						
	162	Total Utility Operating Expenses (L138 + L140 + L147 + L149 + L151 + L153)		5,776,005,854	3,942,157,295	28.06	110,620,645,508
	163						
	164	Net Utility Operating Income		1,539,225,180	1,037,790,393	0.00	-
	165						
	166	Total Requirements (Ln 269+273)		7,315,231,034	4,979,947,688		110,620,645,508
	167						
	168						
COS 923	169	Cash Working Capital Related to NC Sales Tax		6,694,345			

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Duke Energy Corporation

Independent Lobbying Labor Cost Study

August 31, 2016

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William E. Currens, J
Controller, Senior Vice President, Chief Accounting Officer
Duke Energy Business Services LLC
PO Box 37929
Mail Code ST29B
Charlotte, NC 28237

Dear Mr. Currens,

On behalf of KPMG LLP (KPMG), thank you for the opportunity to assist Duke Energy Business Services LLC (DEBS) in the preparation of the independent labor cost study as stipulated in FERC Docket PA-14-2-000 for Duke Energy Corporation and its public utility subsidiaries (Duke Energy). Transmitted herewith is our study report, which is comprised of an executive summary and three separate sections that address each of the deliverables and activities we were requested to perform as described below:

- Lobbying Labor Cost Policy Review
- Comparative Analysis
- Lobbyist Survey

KPMG's services constituted an Advisory engagement conducted under the American Institute of Certified Public Accountants ("AICPA") Standards for Consulting Services. Such services are not intended to be an audit, examination, attestation, special report or agreed-upon procedures engagement as those services are defined in AICPA literature applicable to such engagements conducted by independent auditors. Accordingly, these services do not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.

The observations and recommendations contained in this report are those that we could reasonably derive from the scope of services performed. KPMG has no responsibility for follow-up on our recommendations nor for the ultimate disposition by management of our recommendations. Any eventual implementation of our recommendations including policy decisions are solely the responsibility of Duke Energy management.

The data included in this report was obtained from you and other publicly available sources, as detailed in the report, on or before August 31, 2016. We have no obligation to update our report or to revise the information contained therein to reflect events and transactions occurring subsequent to August 31, 2016.

KPMG cannot guarantee that regulatory authorities would agree with our analysis or that our engagement would foreclose or limit any potential regulatory action. Further, our review may not identify all rating or regulatory issues that may exist or that may become apparent in the future. KPMG's role in

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this engagement was to identify,analyze and summarize the factual information from the publicly available data and/or management provided data. KPMG cannot support or advocate any policy positions as a result of our observations. Should KPMG's participation be requested in Duke Energy meetings or hearings with government officials to explain our review and analysis from a technical perspective, KPMG's participation cannot include private meetings with legislators or occur in a context that could be fairly interpreted as public policy advocacy, lobbying, or otherwise be perceived as impairing our independence.

The scope of work did not require that KPMG make any legal interpretations or render any legal advice, and KPMG and the Company agreed that KPMG's services would not include nor be construed to include the provision by KPMG of legal advice or legal services. All legal interpretations and rendering of legal advice is the Company's responsibility.

We sincerely enjoyed the opportunity to have worked with you and other key DEBS and Duke Energy state lobbyist executives, directors, managers and support staff who have ongoing involvement in compliance related matters and appreciate the input and guidance we received from them over the course of our engagement.

Very truly yours,

KPMG LLP

Thomas R. Peterson
Engagement Managing Director
thomaspeterson@kpmg.com
818 852 6131

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Executive Summary

Overview

KPMG performed an independent[1] study of Duke Energy's affiliates' federal and state cost allocations of internal lobbyist labor, related support staff labor, and associated non-labor costs that should be accounted for in operating and non-operating accounts based on our understanding of Federal Energy Regulatory Commission ("FERC") regulations.

The FERC required Duke Energy to retain an independent third-party entity to conduct a representative labor time study and to determine an appropriate allocation of lobbying costs based on time spent by employees engaged in the activities. The Study is required to be submitted to the FERC by September 28, 2016.[2]

Study components

This Study is comprised of three separate sections as outlined below:

1. Lobbying Labor Cost Allocation Policy Review
    - Federal and State Policy Review
    - Duke Energy Corporation Policy Review
2. Comparative Analysis
    - FERC Form 60, Schedules XV, XVI, and XVII
    - Lobbying Labor Cost Allocation Methods
3. Lobbyist Survey

Scope of Work

KPMG's work is to perform an independent study ("Report" or "Study") of Duke Energy's affiliates' federal and state lobbyists' cost allocations of internal lobbyist labor, support staff, and associated costs that could be accounted for in operating and non-operating accounts based on our understanding of Federal Energy Regulatory Commission ("FERC") regulations.

For the purpose of this study, KPMG's services constituted an Advisory engagement conducted under the American Institute of Certified Public Accountants ("AICPA") Standards for Consulting Services. Such services are not intended to be an audit, examination, attestation, special report or agreed-upon procedures engagement as those services are defined in AICPA literature applicable to such

[1] For purposes of this report, the term "independent" as used herein is not such term as defined by the American Institute of Certified Public Accountants ("AICPA") or other local regulatory authorities in connection with, among other things, audits, reviews, compilations or other attestation services rendered by Certified Public Accountants. The term "independent" as used herein means that KPMG does not have any financial or other relationships with the Company or affiliates that would preclude KPMG from providing you this report for purposes of responding and filing a report with the FERC.

[2] Refer to Summary Finding 28, page 7, FERC Docket PA-14-2-000 dated March 29, 2016

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engagements conducted by independent auditors. Accordingly, these services do not result in the issuance of a written communication to third parties by KPMG directly reporting on financial data or internal control or expressing a conclusion or any other form of assurance.

The scope of work did not call upon KPMG to make any legal interpretations or render any legal advice, and KPMG and the Company agreed that KPMG's services would not include nor be construed to include the provision by KPMG of legal advice or legal services. All legal interpretations and rendering of legal advice is the Duke Energy's responsibility.

Summary level observations and recommendations

Summary level observations and recommendations for each of the three sections of this study are presented below. Supporting documentation for each section, including review, assessment, and survey activities and procedures performed and detailed observations and recommendations, is presented within the body of the Study and associated Appendices.

Section I: Lobbying Labor cost policy review

Purpose:

KPMG reviewed Federal and individual state policies for recording lobbying related expenditures to FERC Account 426.4 as defined under the Code of Federal Regulations (CFR) Section 367.4264 to understand if there were any major guideline differences between the jurisdictions in which Duke Energy operates.

Observations:

a) We found that in general, all jurisdictions follow the lobbying definitions noted in CFR Section 367.4264 for reporting purposes. Some states, such as Indiana, may have more restrictive lobbying definitions, however Duke Energy policies follow the Federal guidelines and, if necessary, will adjust for any state jurisdictional differences from the CFR for jurisdictional reporting or rate case purposes.

Recommendations:

a) None

Section II: Comparative analysis, including FERC Form 60, Schedules XV, XVI, and XXI

Most utility holding companies deploy lobbying resources through a centralized services company, and Duke Energy is no exception. Of the 32 direct lobbyist and support personnel identified by Duke Energy and included in this Study, 23 (72%) were deployed by DEBS and therefore subject to the reporting requirements of the FERC Financial Report Form No. 60: Annual Report of Centralized Service Companies ("FERC Form 60"). The following represent a summary of the analyses performed.

1) FERC Form 60, Schedule XV – Account 426.4 expenses as a percentage of Total Operating Expenses.

Purpose: Schedule XV reports a comparative income statement for utility service companies, with Line 37 detailing expenditures related to Account 426.4. The purpose of this review was to understand any major gaps in DEBS charges to this account compared to the peer group[3] as obtained from the 2015 Form 60 publicly available reports.

[3] The peer group is defined further in Section II of this Study.

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Observations:

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XV data revealed Account 426.4 expenditures for DEBS was 0.41% of total operating expenses. The peer group average was .37% with a median of .31%.

Recommendations:

a) None

2) FERC Form 60, Schedule XVI – Direct Account 426.4 expenses as a percentage of Total Account 426.4 Expenses.

Purpose: Schedule XVI reports direct and indirect charges to affiliate and non-affiliate companies with Line 25 outlining Account 426.4 expenditures. The purpose of this assessment was to gain a better understanding of how lobbying expenses are charged to the account relative to the peer group as obtained from publicly available FERC Form 60 reports for the calendar year ended 2015.

Observations:

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XVI data revealed that Direct Account 426.4 expenditures as a percentage of total Account 426.4 expenditures for DEBS was 33% The peer group average was 70% with a median result of 51%.

b) The range of the peer group averages was quite wide (0% to 99%) indicating that the standard industry definition being used in the application of Form 60 "direct" versus "indirect" charges to the account may be more of a function of how the peer group service companies are organized within their respective operating systems. That is, if all system lobbying resources reside in the service company, direct charges to associated companies would be higher on average. If only lobbying management and Federal lobbying resources reside in the service company, direct charges to associated companies would be lower on average.

c) Discussions with DEBS Finance personnel revealed that 12 of the 23 DEBS resources (52%) are reporting through the Federal External Affairs and Strategy Policy function which by nature requires a general, or indirect, allocation to affiliate customers. The makeup of DEBS lobbying resources would point toward a lower direct charge ratio relative to peers.

d) Discussions with DEBS Finance personnel noted that the Duke Energy deploys a charge code approach that allows all lobbying resources (both residing in DEBS and in the local state jurisdictions) the opportunity to directly charge the benefitting company. The ability to direct charge is reinforced with all system-wide lobbying resources through annual training and educational programs.

Recommendations:

a) None – Duke Energy was not an outlier relative to the peer group and should continue to promote the use of direct charging mechanisms with lobbying personnel system-wide.

3) FERC Form 60, Schedule XXI – Methods of Allocation.

Purpose: Schedule XXI reports how utility service companies bill *indirect* charges through allocation methodologies to affiliate and non-affiliate customers. The purpose of this assessment was to understand if billings to associated companies applied on a basis similar to that used in the industry relative to the peer group as obtained from publicly available FERC Form 60 reports for calendar year ended 2015.

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Observations:

a) DEBS uses a "3-factor formula" based on the weighted average gross margin ratio, labor dollars ratio, and the property, plant and equipment ratio for allocation purposes to bill utility subsidiaries. This factor is included in DEBS yearly Cost Allocation Manual submission to the FERC for approval.

b) Review of peer group Form 60, Schedule XXI noted similar "general" allocators used for this cost pool.

Recommendations:

a) None

Section III: Lobbyist Survey

The purpose of the Lobbyist Survey was to develop a time labor study for use by Duke Energy system companies as a basis for allocation of labor related costs to the appropriate accounts. The scope of the Study included all personnel within the Duke Energy system companies associated with lobbying functions, whether performing direct lobbyist or general lobbying support activities.

Observations:

a) Activity group 1.0 – Manage External Relationships represents the overall system percentage (53%) that would be applied to the Below-The-Line CFR Account 426.4. Activity group 2.0 – Manage Internal Relationships represents the overall system percentage (47%) that would be applied to the Above-The-Line CFR Account 920.0.

b) Total system results noted above represent only the simple average of all respondents and are not dollar weighted. Results also vary by individual and by the jurisdiction for which the services were provided.[4]

Recommendations:

a) Duke Energy should apply the detailed study results for charges beginning January 1, 2016 and forward. We recommend the individual respondent survey results be applied to the time entry account code structures currently in place.

b) Duke Energy should institute policies and procedures to periodically update these study results to help ensure any changes in personnel or lobbyist activities are captured and adjusted. These procedures should ensure that any material changes in personnel or responsibilities can be identified and updated on a case by case basis if required.

c) Duke Energy should continue to reinforce and promote the ability to set up specific project charge codes for individuals to capture and assign time and expenses that are outside the parameters of the time labor study activities.

[4] Results by jurisdiction are provided in Appendix D of this report and results by individual are provided in Appendix E of this report.

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Section I: Lobbying Labor Cost Policy Review

Purpose and scope

The purpose of this work was to review Duke Energy's and their respective utility subsidiaries'[5] existing requirements for lobbying costs relative to industry standards. KPMG conducted interviews[6] with lobbying and regulatory personnel, and reviewed documentation requests[7] to understand how costs were being both assigned and recovered under Federal and / or state requirements. In general, charges to Account 426.4 (defined below) are not included or recoverable for ratemaking purposes.

Duke Energy operates in 5 states and 11 separate jurisdictions for rate purposes[8], including the Federal function in which costs are captured at the service company level (DEBS) and subsequently billed to the jurisdictional entities through allocations. The lobbying function is organized with resources located at both the DEBS level and within the individual state subsidiaries. Of the 32 lobbying resources, both management and support, 23 are located within DEBS.

Federal and state policy review

Federal requirements for lobbying costs are found in the Code of Federal Regulations ("CFR") Section 367.4264 which states:

Account 426.4, Expenditures for certain civic, political and related activities

a) This account must include expenditures for the purpose of influencing public opinion with respect to the election or appointment of public officials, referenda, legislation, or ordinances (either with respect to the possible adoption of new referenda, legislation or ordinances or repeal or modification of existing referenda, legislation or ordinances) or approval, modification, or revocation of franchises; or for the purpose of influencing the decisions of public officials.

b) This account must not include expenditures that are directly related to appearances before regulatory or other governmental bodies in connection with an associate utility company's existing or proposed operations.

State policies generally have adopted the CFR Section 367.4264 definitions noted above with the one exception of Indiana. Indiana Code 2-7-1-9 appears to be more restrictive by defining "lobbying" as *only* communicating by any means, or paying others to communicate by any means, with any legislative person for the purpose of influencing any legislative action. All states within the Duke Energy system require periodic report submittals of internal lobbying costs and related expenditures.

Duke Energy Corporation policy review

Duke Energy system companies, based on our interviews, have adopted the CFR accounting requirements and definitions as noted above for compliance and recording purposes.

[5] The scope of this Study did not include any review of internal control procedures or management oversight of those procedures to provide assurance that time reporting and tracking was being followed.
[6] A complete listing of Duke Energy personnel interviewed can be found in Appendix A.
[7] A complete listing of documents reviewed can be found in Appendix B.
[8] See Appendix C for a complete listing as was used in the Lobbyist Survey – Format.

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Observations and recommendations

Observations:

a) We found that in general, all jurisdictions follow the lobbying definitions noted in CFR Section 367.4264 for reporting purposes. Some states, such as Indiana, may have more restrictive lobbying definitions, however Duke Energy follows the Federal guidelines and, if necessary, will adjust for any state jurisdictional differences from the CFR for jurisdictional reporting or rate case purposes.

Recommendations:

a) None

Section II: Comparative Analysis

Purpose and scope

The purpose of this work was to assess Duke Energy's current environment compared to a sample of other utility holding companies with respect to lobbying costs charged to Account 426.4 - Expenditures for certain Civic, Political and Related activities. The analysis was performed to assess the gaps between DEBS and other comparable utility services companies.

Most utility holding companies deploy lobbying resources through a centralized services company, and Duke Energy is no exception. Of the 32 direct lobbyist and support personnel identified by Duke Energy and included in this Study, 23 (72%) were deployed by DEBS and therefore subject to the reporting requirements of the FERC Financial Report Form No. 60: Annual Report of Centralized Service Companies ("FERC Form 60").

Results of this analysis provided KPMG with information to corroborate interview needed for development of the labor study noted in Section III of this report. KPMG utilized the publicly available FERC Form 60 submittals for the following selected metrics and compared DEBS results to those of a peer group comprised of seven (7) utility service companies with similar financial, operational, and jurisdictional characteristics.

- Civic, Political, and Related Expenditures (Account 426.4) as a percentage of Operating Expenses as stated on FERC Form 60, Schedule XV.

- Direct[9] Civic, Political, and Related Expenditures (Account 426.4) as a percentage of Total Civic, Political, and Related Expenditures as stated on FERC Form 60, Schedule XVI.

The peer group was comprised of the following entities which were discussed with Duke Energy prior to the commencement of work:

- American Electric Power Service Corporation (AEP)
- Ameren Services Company (Ameren)
- Entergy Services, Incorporated (ETR)
- Exelon Business Services Company, LLC (EXC)
- FirstEnergy Services Company (FE)
- Southern Company Services, Incorporated (SOU)
- Xcel Energy Services Incorporated (XEL)

[9] The term "Direct" with regard to a FERC Form 60 means charges from the service company function that were not allocated to system affiliate customers using some type of general formula.

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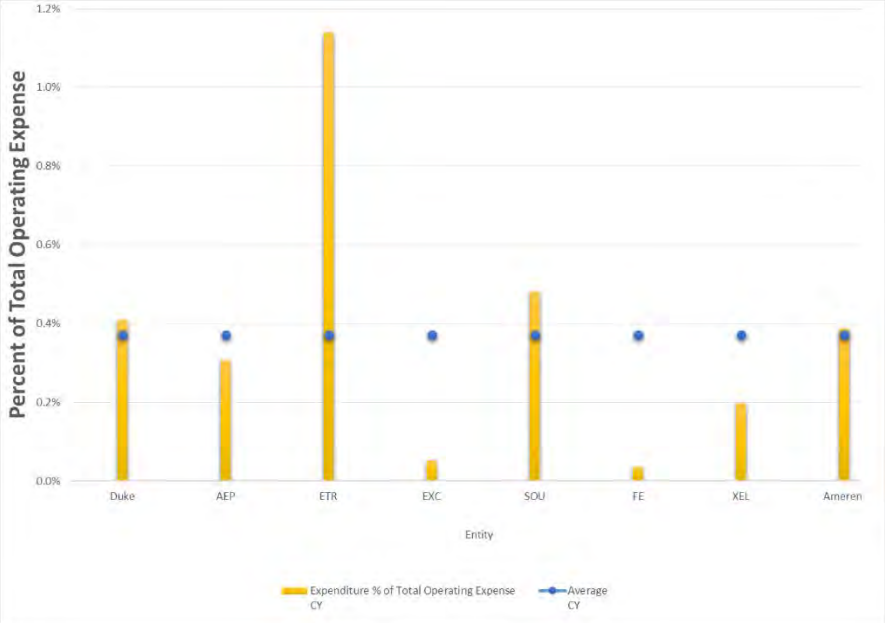
FERC filings

FERC Form 60, Schedule XV – Account 426.4 expenses as a percentage of Total Operating Expenses

Schedule XV reports a comparative income statement for utility service companies, with Line 37 detailing expenditures related to Account 426.4. The chart below highlights the results from each of the peer group service company data relative to DEBS.



Account 426.4 Expenditures as a Percent of Total Operating Expenses - 2015

Observations:

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XV data revealed Account 426.4 expenditures for DEBS was 0.41% of total operating expenses. The peer group average was .37% with a median of .31%.

Recommendations:

a) None

FERC Form 60, Schedule XVI – Direct Account 426.4 expenses as a percentage of Total Operating Expenses

Schedule XVI reports direct and indirect charges to affiliate and non-affiliate companies with Line 25 outlining Account 426.4 expenditures. The following charts show the percentage of direct to indirect charges for each of the peer group companies.

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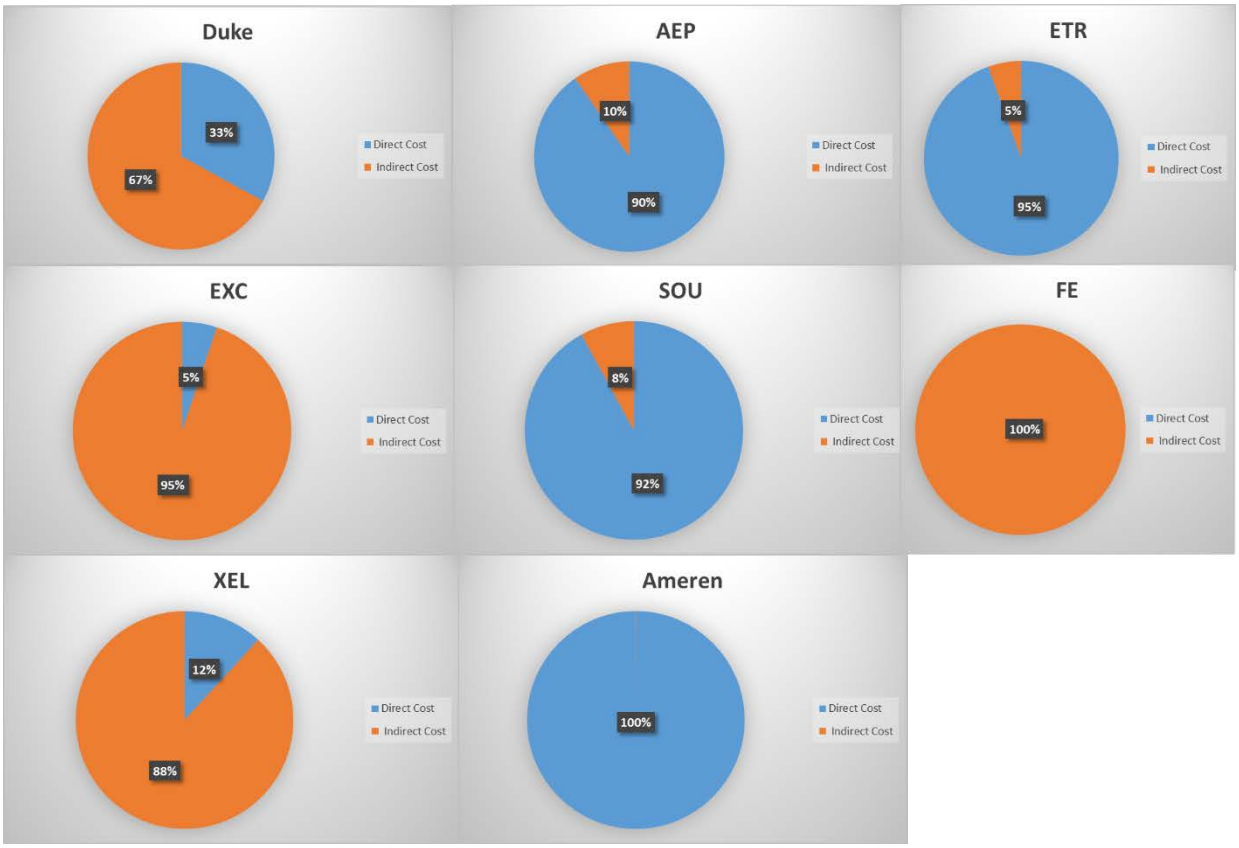

Account 426.4 Expenditures - Associate Company Direct vs. Indirect cost

Observations:

a) For the year ended December 31, 2015, comparative analysis of FERC Form 60, Schedule XVI data revealed that direct Account 426.4 expenditures as a percentage of total Account 426.4 expenditures for DEBS was 33% The peer group average was 70% with a median result of 51%.

b) The range of the peer group averages was quite wide (0% to 99%) indicating that the standard industry definition being used in the application of Form 60 "direct" versus "indirect" charges to the account may be more of a function of how the peer group service companies are organized within their respective operating systems. That is, if all system lobbying resources reside in the service company, direct charges to associated companies would be higher on average. If only lobbying management and Federal lobbying resources reside in the service company, direct charges to associated companies would be lower on average.

c) Discussions with DEBS Finance personnel revealed that 12 of the 23 DEBS resources (52%) are reporting through the Federal External Affairs and Strategy Policy function which by nature requires a general, or indirect, allocation to affiliate customers. The makeup of DEBS lobbying resources would point toward a lower direct charge ratio relative to peers.

d) Discussions with DEBS Finance personnel noted that the Duke Energy deploys a charge code approach that allows all lobbying resources (both residing in DEBS and in the local state jurisdictions) the opportunity to directly charge the benefitting company. The ability to direct charge is reinforced with all system-wide lobbying resources through annual training and educational programs.

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Recommendations:

a) None – Duke Energy should continue to promote the use of direct charging mechanisms with lobbying personnel system-wide.

FERC Form 60, Schedule XXI – Methods of Allocation

Schedule XXI reports how utility service companies allocate indirect charges to affiliate and non-affiliate customers. Costs for shared services are distributed to affiliates within Duke Energy through (i) direct charges, (ii) distribution or (iii) allocation. Costs are direct charged to the extent possible. Costs that cannot be direct charged can be distributed to the applicable business units using specific percentages if known. Costs that cannot be direct charged or distributed are allocated to the business units receiving the benefit using reasonable allocation methods.

Observations:

a) DEBS uses a "3-factor formula" based on the weighted average gross margin ratio, labor dollars ratio, and the property, plant and equipment ratio for allocation purposes to bill utility subsidiaries. This factor is included in DEBS yearly Cost Allocation Manual submission to the FERC for approval.

b) Review of peer group Form 60, Schedule XXI noted similar "general"[10] allocators used for this cost pool.

Recommendations:

a) None

[10] The term "general" allocators used herein refers to methods in which multiple utility entities are billed by their respective services company. For example, Exelon uses a Modified Massachusetts Formula (MMF) which uses a combination of gross revenues, assets and direct labor that is commonly used in the industry. Xcel Energy uses another type of general allocator also termed the 3-factor formula which uses a combination of revenues, employees and total assets. FirstEnergy uses a general allocator termed "Multiple Factor Utility". All of these general allocators are reviewed and approved by FERC.

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Section III: Lobbyist Survey

Purpose and scope

The purpose of the Lobbyist Survey and related steps was to conduct a time labor study for use by Duke Energy system companies as a basis for allocation of labor related lobbying costs to the appropriate accounts. The scope of the Study included all personnel within the Duke Energy system companies associated with lobbying functions, whether performing direct lobbyist or general support activities for the lobbying functions.

As background, Duke Energy system companies deploy a system of time reporting that allows all employees to directly charge or distribute activity costs to the proper utility or jurisdiction at time entry. Study results can be applied to the direct or distributed charge codes utilized for allocation of costs either to CFR account 426.4 ("Below the line") or CFR account 920.0 ("Above the line").

The Study did not assess or include Federal or state jurisdictional rate treatment of these costs subsequent to the initial allocations to the accounts noted above.

Approach

The lobbyist survey approach is depicted below:

1. Develop Lobbying Cost Survey – through a series of interviews with select Duke Energy lobbyist and support staff, as well as the review of internal Duke Energy or DEBS documentation related to lobbying costs, KPMG developed a survey based on typical activities that would be performed throughout the year. The complete survey, along with instructions, examples and structure, can be found in Appendix C.

2. Distribute Lobbying Cost Survey – surveys were electronically distributed to all lobbyist and support personnel identified by Duke Energy. Individuals were instructed to complete the survey and send the individual results directly back to KPMG.

3. Review and Assess Lobbying Cost Survey – Upon receipt of all surveys, KPMG then analyzed and summarized the results by person and by jurisdiction. Part of the analysis involved going back to certain individuals to validate their individual survey responses.[11]

Summarized survey responses

The following represents a high level summary of the Duke Energy system-wide survey responses by primary activity level. Detailed survey results have been supplied to Duke Energy.

[11] All survey validated results are located in the detail Survey workpapers supplied to Duke Energy

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Total System

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	53%
1.1	Provide Direct Lobbying Services - Federal	8%
1.2	Provide Direct Lobbying Services –State and Local	17%
1.3	Evaluate and Communicate Strategic Positions	17%
1.4	Develop and Maintain Relationships	12%
2.0	Manage Internal Relationships	47%
2.1	Provide Internal Lobbying Services	16%
2.2	Provide Internal Non-Lobbying Services	12%
2.3	Provide Other Operational Services	19%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

Observations and recommendations

Observations:

a) Activity group 1.0 – Manage External Relationships represents the overall system percentage (53%) that would be applied to the Below-The-Line CFR Account 426.4. Activity group 2.0 – Manage Internal Relationships represents the overall system percentage (47%) that would be applied to the Above-The-Line CFR Account 920.0.

b) Total system results noted above represent only the simple average of all respondents and are not dollar weighted. Results also vary by individual and by the jurisdiction for which the services were provided.[12]

Recommendations:

a) Duke Energy should apply the detailed study results for charges beginning January 1, 2016 and forward. We recommend the individual respondent survey results be applied to the time entry account code structures currently in place.

b) Duke Energy should institute policies and procedures to periodically update these study results to help ensure any changes in personnel or lobbyist activities are properly captured and adjusted. These procedures should ensure that any material changes in personnel or responsibilities can be identified and updated on a case by case basis if required.

d) Duke Energy should continue to reinforce and promote the ability to set up specific project charge codes for individuals to capture and assign time and expenses that are outside the parameters of the time labor study activities.

[12] Summarized results by jurisdiction and by individual are provided in Appendix D and Appendix E of this report, respectively

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Appendix A: Interview List

Over the course of this assessment, KPMG conducted a series of interviews with Duke Energy key lobbyist, support staff, regulatory and finance personnel to gain a better understanding of how costs flowed through the account systems and the types of activities performed. Key personnel who were interviewed included the following:

Employee ID[13]	Title	Interview Group
125669	Managing Director Rates & Regulatory Strategy - Carolinas	Rates - Carolinas
265672	Director Federal Government Affairs SC	Lobbyist - Federal
359638	Vice President Indiana Government Affairs	Lobbyist - Indiana
019577	Director Rates & Regulatory Strategy-OH/KY	Rates - Ohio/Kentucky
343011	Director Rates & Regulatory Strategy-FL	Rates - Florida
026641	Director State Government Affairs	Lobbyist - Ohio
010565	Vice President Government & Community Affairs	Lobbyist - Kentucky
358441	Director State Government Affairs	Lobbyist - Florida
122866	Director Allocations & Reporting	DEBS - Cost Allocations
369923	Executive Assistant	Support Staff - Indiana
153865	Vice President Government Affairs	Lobbyist – South Carolina
338568	Senior Administrative Specialist	Support Staff – South Carolina
284280	Vice President Government Affairs-NC	Lobbyist – North Carolina
112288	Director Rates & Regulatory Planning	Rates - Indiana
125764	Manager Accounting	Rates - Transmission

[13] For purposes of this publicly available report we use employee ID numbers rather than individual names.

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Appendix B: Documents Reviewed

Over the course of this assessment, KPMG requested and reviewed the following list of documents to gain a better understanding of how lobbyist costs flowed through the system of accounts.

Document Name	Employee ID[14]
State Codes / Lobbying Definitions	017666
FERC audit work papers and FERC responses	235377
FERC Form 60s for 2014 & 2015	335729
Time Capture Process Code Structures	335729
2015 Actual Data Charges by Responsibility Center, Operating Unit, Business Unit, Process Code and Resource Type	335729
2016 DEBS Allocation Tables	122866
2013 DEBS Cost Allocation Manual	122866
Example Data request response to Customer advocacy group (NC)	125669
Spreadsheet example of all sources charging lobbying codes	335729
Federal "Heat Map" Presentation (Federal Issues Update)	367150
Copies of latest Indiana lobbyist reports and "Lobbying" definition	359638
Copy of the H-22 schedule from latest rate case (Ohio Kentucky)	019577
Copies of the C-18 schedules used in FLA rate case support	343011
Copy of South Carolina Lobbying definitions	017666
Copies of South Carolina Lobbying Ethics reports	338568
2009 rate support schedules with proforma entries for lobbying	112288

[14] For purposes of this publicly available report we use employee ID numbers rather than individual names.

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Appendix C: Labor Survey Structure

Instructions: The following represents the instructions sent to all survey respondents.

1. INTRODUCTION	**In response to a FERC merger audit finding regarding the allocation of lobbyist and support labor costs, Duke Energy engaged KPMG to perform an independent review of system-wide lobbyist labor costs and activities. The results of the study will be analyzed by KPMG and, along with any policy recommendations, a report will be prepared and filed with the FERC in late September, 2016.** **It is also important to understand that the study and associated documentation will only be used on a going forward basis to provide support for time entry allocation purposes with periodic updates to substantiate and document sound policy and procedure. This is not an audit but a view forward, so any past practices or entrenched beliefs should be discounted.** **The purpose of the study is to gain your individual input as a subject matter resource as to the amount of time spent in various activities. Study results will be treated as confidential with respect to the report, and KPMG may have follow up questions upon submittal.**
2. REFERENCE GUIDE TAB	**The tab entitled "Reference Guide" is for your use in understanding the types of activities and tasks being performed. This lobbyist "activity dictionary" was prepared using a combination of external sources and data request responses and the results of interviews performed with executive management, lobbyists and staff support personnel within the Duke system.** **This survey preparation work resulted in a list of 16 common, yet representative, activities related to lobbying departments and functions.** **Prior to filling out the Activity Survey Tab, we suggest you review the activity definitions and the associated example activities provided to gain a familiarity and to begin to formulate your individual estimates of time spent.**
3. ACTIVITY SURVEY TAB	**On the far left of the tab you will see the 16 activities listed under two processes, External and Internal facing relationship management. To the right of the activities listed are drop down cells containing increments of 5% and should be used to estimate your individual participation by the jurisdiction listed in Columns F-R. Please complete your estimate of time by jurisdiction and pay attention to Cell E-1 which will maintain a running total and turn "Green" when your sum total estimates equal 100%.** **While every attempt to produce a relevant survey for your use was made, there may be an occasion in which a listed activity that you perform cannot be grouped within these categories. Therefore each activity grouping has a <blank> cell for you to fill out should you feel the need.** **Additionally at the bottom of the survey chart, a blank notes / comments section has been provided for any feedback you deem required for us to better understand the results.** **Finally, we understand that in any given business situation responsibilities may change, or special projects may come up. The purpose of the survey is to gain an understanding of what a typical year currently looks like for you. Special project work that has come up in the past or that may come up in the future should be directly charged to individual project codes set up by your Finance representative and not reflected here. Similarly if normal, ongoing business responsibilities change next year, that is understandable and would be taken care through the future periodic refreshes of this study.**
4. SURVEY COMPLETION	**We thank you in advance for your timely participation in this important study. Should you have any questions or problems, please feel free to email or call the KPMG project team: Mark Everette (markeverette@kpmg.com/312-560-9159) or Doug Centola (dcentola@kpmg.com/585-760-4492).** **UPON COMPLETION, ALL RESPONSES SHOULD BE SENT DIRECTLY TO DOUG CENTOLA [dcentola@kpmg.com] by COB on 08/03/16.**

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Appendix C: Labor Survey Structure

Reference Guide

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

Primary Lobbying Activity Groups				Example Activities
1.0	Manage External Relationships			
1.1		Provide Direct Lobbying Services - Federal		
1.1.1			Contacting Congressional Members	• Contacting a member of Congress to discuss pending or proposed legislation, the company's opinion of pending legislation, a legislative proposal. • Communication with a legislative body with regard to a decision, or possible decision, by the body which may, or may not be, consistent with the company's position. • Managing and preparing testimony before a Congressional committee. • Attending a Congressional committee or hearing (as a member of the audience).
1.1.2			Contacting Executive and Agency Officials	• Contacting an executive branch government or administrative official or employee who may participate in the formulation of legislation, where the principal purpose of the communication is to influence legislation. • Holding meetings with agency officials to discuss legislative issues.
1.1.3			Contacting Members of the General Public	• Contacting members of the general public in a communication which refers to specific legislation, reflects a view on such legislation, and (directly or indirectly) encourages the recipient to take action. • Attempting to influence the public in voting on a referendum.

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Appendix C: Labor Survey Structure

Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

Primary Lobbying Activity Groups				Example Activities
1.0	Manage External Relationships			
1.2		Provide Direct Lobbying Services –State and Local		
1.2.1			Contacting Congressional Members	• Contacting a member of Congress to discuss pending or proposed legislation, the company's opinion of pending legislation, a legislative proposal. • Communication with a legislative body with regard to a decision, or possible decision, by the body which may, or may not be, consistent with the company's position. • Managing and preparing testimony before a Congressional committee. • Attending a Congressional committee or hearing (as a member of the audience).
1.2.2			Contacting Executive and Agency Officials	• Contacting an executive branch government or administrative agency official or employee who may participate in the formulation of legislation, where the principal purpose of the communication is to influence legislation. • Holding meetings with agency officials to discuss legislative issues.
1.2.3			Contacting Members of the General Public	• Contacting members of the general public in a communication which refers to specific legislation, reflects a view on such legislation, and (directly or indirectly) encourages the recipient to take action. • Attempting to influence the public in voting on a referendum.

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Appendix C: Labor Survey Structure

Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

Primary Lobbying Activity Groups				Example Activities
1.0	Manage External Relationships			
1.3	Evaluate and Communicate Strategic Positions			
1.3.1			Analyze and Draft Legislation	• Analyzing bills, laws and legislation and their impacts on or consistency with corporate strategy and priorities. • Developing, drafting or editing legislation.
1.3.2			Develop, Monitor and Publish Research	• Conducting research to support a legislative initiative. • Direct or publish analyses, studies, or research which reflects a view on specific legislation. • Advocating a particular position or viewpoint within analyses, studies, or research to enable the public or an individual to form an independent opinion or conclusion.
1.3.3			Promote Strategic Positioning	• Conducting coalition meetings with other external organizations to share information to be used in lobbying and/or to devise lobbying strategy.
1.4	Develop and Maintain Relationships			
1.4.1			Promote Corporate Image	• Attending or participating in networking events on behalf of the Company. • Attending or participating in charity or philanthropic events on behalf of the Company. • Managing relationships with independent organizations (PACs, NGOs, Non-profits, etc.).
1.4.2			Manage Corporate Resources	• Managing and monitoring the funding of strategic sponsorships.

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Appendix C: Labor Survey Structure

Reference Guide - Continued

The following represents the activity group reference guide with example activities provided to the survey respondents for assistance in filling out individual survey results.

Primary Lobbying Activity Groups				Example Activities
2.0	Manage Internal Relationships			
2.1		Provide Internal Lobbying Services		
2.1.1			Communicate Strategy and Positions	• Communicating company positions and strategies on pending or proposed legislation to employees of Duke Energy. • Contacting company personnel, departments and leadership to support lobbying efforts, to encourage legislative contact, and to promote Duke PAC membership.
2.1.2			Support Internal Lobbying Efforts	• Coordinating and meeting with internal departments or resources to support company positioning. • Organizing and managing issues and strategies with other departments (such as Environmental, Community or Regulatory Affairs) to determine appropriate and consistent messaging on positions. • Conducting advocacy training.
2.2		Provide Internal Non-Lobbying Services		
2.2.1			Manage or Support Other Departments	• Delivering any management or support activities (that are not associated with lobbying activities in 2.1 above) to other departments or functions within the company.
2.3		Provide Other Operational Services		
2.3.1			Manage Constituent Inquiries	• Assisting legislative officials with solving any constituent inquiries/issues (power outages, downed power lines, billing questions etc.).
2.3.2			Provide General Office Management Support	• Coordinating meetings, travel arrangements and training events. • Managing executive calendars, supporting general office needs (facilities, supplies, technology support etc.). • Processing and tracking invoices, time and expense coding and input, report generation and accounting.

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Appendix C: Labor Survey Structure

Format

The following represents the actual survey format sent to all respondents.

		<NAME>	Estimated Percentage of Time Spent by Jurisdiction													
		Primary Lobbying Activity Groups	Kentucky - Electric Only	Kentucky - Gas Only	Kentucky - All	Ohio - Electric Only	Ohio - Gas Only	Ohio - All	Indiana	North Carolina - DEC	North Carolina - DEP	South Carolina - DEC	South Carolina - DEP	Florida	Federal	Other - Specify
1.0		Manage External Relationships														
1.1		Provide Direct Lobbying Services - Federal														
1.1.1		Contacting Congressional Members														
1.1.2		Contacting Executive and Agency Officials														
1.1.3		Contacting Members of the General Public														
1.1.4		<Other - please describe>														
1.2		Provide Direct Lobbying Services –State and Local														
1.2.1		Contacting Congressional Members														
1.2.2		Contacting Executive and Agency Officials														
1.2.3		Contacting Members of the General Public														
1.2.4		<Other - please describe>														
1.3		Evaluate and Communicate Strategic Positions														
1.3.1		Analyze and Draft Legislation														
1.3.2		Develop, Monitor and Publish Research														
1.3.3		Promote Strategic Positioning														
1.3.4		<Other - please describe>														
1.4		Develop and Maintain Relationships														
1.4.1		Promote Corporate Image														
1.4.2		Manage Corporate Resources														
1.4.3		<Other - please describe>														
2.0		Manage Internal Relationships														
2.1		Provide Internal Lobbying Services														
2.1.1		Communicate Strategy and Positions														
2.1.2		Support Internal Lobbying Efforts														
2.1.3		<Other - please describe>														
2.2		Provide Internal Non-Lobbying Services														
2.2.1		Manage or Support Other Departments														
2.2.2		<Other - please describe>														
2.3		Provide Other Operational Services														
2.3.1		Manage Constituent Inquiries														
2.3.2		Provide General Office Management Support														
2.3.3		<Other - please describe>														
Total Estimated Percentage of Time Spent by Jurisdiction			0	0	0	0	0	0	0	0	0	0	0	0	0	0
													GRAND TOTAL			0

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Appendix D: Labor Survey Results by Jurisdiction

Kentucky		
	Primary Lobbying Activity Groups	**Breakdown**
1.0	Manage External Relationships	52%
1.1	Provide Direct Lobbying Services - Federal	3%
1.2	Provide Direct Lobbying Services –State and Local	14%
1.3	Evaluate and Communicate Strategic Positions	16%
1.4	Develop and Maintain Relationships	19%
2.0	Manage Internal Relationships	48%
2.1	Provide Internal Lobbying Services	10%
2.2	Provide Internal Non-Lobbying Services	21%
2.3	Provide Other Operational Services	17%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

OHIO		
	Primary Lobbying Activity Groups	**Breakdown**
1.0	Manage External Relationships	65%
1.1	Provide Direct Lobbying Services - Federal	0%
1.2	Provide Direct Lobbying Services –State and Local	24%
1.3	Evaluate and Communicate Strategic Positions	26%
1.4	Develop and Maintain Relationships	14%
2.0	Manage Internal Relationships	35%
2.1	Provide Internal Lobbying Services	17%
2.2	Provide Internal Non-Lobbying Services	9%
2.3	Provide Other Operational Services	8%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

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Appendix D: Labor Survey Results by Jurisdiction

Indiana

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	41%
1.1	Provide Direct Lobbying Services - Federal	0%
1.2	Provide Direct Lobbying Services –State and Local	23%
1.3	Evaluate and Communicate Strategic Positions	7%
1.4	Develop and Maintain Relationships	10%
2.0	Manage Internal Relationships	59%
2.1	Provide Internal Lobbying Services	12%
2.2	Provide Internal Non-Lobbying Services	21%
2.3	Provide Other Operational Services	26%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

North Carolina

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	71%
1.1	Provide Direct Lobbying Services - Federal	0%
1.2	Provide Direct Lobbying Services –State and Local	28%
1.3	Evaluate and Communicate Strategic Positions	22%
1.4	Develop and Maintain Relationships	21%
2.0	Manage Internal Relationships	29%
2.1	Provide Internal Lobbying Services	16%
2.2	Provide Internal Non-Lobbying Services	2%
2.3	Provide Other Operational Services	11%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

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Appendix D: Labor Survey Results by Jurisdiction

South Carolina

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	50%
1.1	Provide Direct Lobbying Services - Federal	0%
1.2	Provide Direct Lobbying Services –State and Local	20%
1.3	Evaluate and Communicate Strategic Positions	25%
1.4	Develop and Maintain Relationships	5%
2.0	Manage Internal Relationships	50%
2.1	Provide Internal Lobbying Services	13%
2.2	Provide Internal Non-Lobbying Services	7%
2.3	Provide Other Operational Services	30%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

Florida

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	45%
1.1	Provide Direct Lobbying Services - Federal	0%
1.2	Provide Direct Lobbying Services –State and Local	28%
1.3	Evaluate and Communicate Strategic Positions	12%
1.4	Develop and Maintain Relationships	5%
2.0	Manage Internal Relationships	55%
2.1	Provide Internal Lobbying Services	12%
2.2	Provide Internal Non-Lobbying Services	3%
2.3	Provide Other Operational Services	40%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

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Appendix D: Labor Survey Results by Jurisdiction

Federal

	Primary Lobbying Activity Groups	Breakdown
1.0	Manage External Relationships	53%
1.1	Provide Direct Lobbying Services - Federal	24%
1.2	Provide Direct Lobbying Services –State and Local	0%
1.3	Evaluate and Communicate Strategic Positions	16%
1.4	Develop and Maintain Relationships	12%
2.0	Manage Internal Relationships	47%
2.1	Provide Internal Lobbying Services	22%
2.2	Provide Internal Non-Lobbying Services	16%
2.3	Provide Other Operational Services	10%
Total Estimated Percentage of Time Spent by Jurisdiction		100%

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Appendix E: Labor Survey Results by Resource

The following table depicts the individual survey results by individual respondent. Most respondents are listed more than once in that they will charge to multiple jurisdictions.

Jurisdiction	Employee ID #	Responsibility Center	Business Unit's Utility	Survey AC 426	Survey AC 920	Survey Other	Comments / Notes
Kentucky	010565	State President OH/KY Staff	Kentucky - Elect.	52%	17%		Account split between KY - ELE and GAS is 80/20 per validated survey
Kentucky	010565	State President OH/KY Staff	Kentucky - Gas	13%	4%		
Kentucky	010565	State President OH/KY Staff	Kentucky - Elect.			1%	Economic Development activities split between KY - ELE and GAS is 67/33
Kentucky	010565	State President OH/KY Staff	Kentucky - Gas			1%	
Ohio	010565	State President OH/KY Staff	Ohio - Gas			2%	Economic Development activities split between OH - ELE and GAS is 80/20 per Survey
Ohio	010565	State President OH/KY Staff	Ohio - Elect.			10%	
Indiana	015201	Government Affairs - IN	Indiana	45%	55%		Direct from Validated Survey
Kentucky	018749	State President OH/KY Staff	Kentucky - Elect.	9%	4%		Jurisdictional split 64% for KY- ELE and GAS per prior fixed distribution
Kentucky	018749	State President OH/KY Staff	Kentucky - Gas	5%	2%		
Ohio	018749	State President OH/KY Staff	Ohio - Gas	21%	9%		Jurisdictional split 37/63 for OH - GAS and ELE per prior fixed distribution
Ohio	018749	State President OH/KY Staff	Ohio - Elect.	35%	15%		
Federal	025421	Federal Policy & Gov Affairs	DEBS - FED		100%		Direct from Validated Survey
Ohio	026641	Govt & Community Affairs Ohio	Ohio - Gas	35%	15%		Respondent survey showed OHIO "All" in addition to time spent between electric and gas. KPMG reallocated "ALL" 50/50 to the ELE and GAS jursidiction based on the level of direct charges rates.
Ohio	026641	Govt & Community Affairs Ohio	Ohio - Elect.	35%	15%		
Federal	034688	Governmental Affairs - Federal	DEBS - FED	70%	30%		Direct from Validated Survey
Federal	048625	Rates & Reg Strategy-OH/KY	DEBS - FED		20%		Direct from Validated Survey
Kentucky	048625	Rates & Reg Strategy-OH/KY	DEBS - KY ELE		32%		Account 920 jurisdictional split between KY - ELE and GAS is 80/20 per Survey Validation
Kentucky	048625	Rates & Reg Strategy-OH/KY	DEBS - KY GAS		8%		
Ohio	048625	Rates & Reg Strategy-OH/KY	DEBS - OH ELE		25%		Account 920 spllits based on direct survey results from respondent surveys representing a 63% / 37% split for OH ELE and OH GAS
Ohio	048625	Rates & Reg Strategy-OH/KY	DEBS - OH Gas		15%		
Ohio	097563	Govt & Community Affairs Ohio	Ohio - Elect.	43%	19%		Respondent validation noted a 62/38 split between OH - ELE and GAS
Ohio	097563	Govt & Community Affairs Ohio	Ohio - Gas	27%	11%		
Federal	107880	Env Affairs & Stakeholder Eng	DEBS - FED	5%			Direct from Validated Survey- Other represents non-lobbying activities
South Carolina	107880	Environmental Affairs	Carolinas (DEP)	25%			
South Carolina	107880	Environmental Affairs	Carolinas (DEP)			25%	
South Carolina	107880	Environmental Affairs	Carolinas (DEC)	30%	15%		
South Carolina	153865	SC State Gov't Affairs	Carolinas (DEC)	43%	8%		Respondent validation discussions noted a 50/50 Split between SC DEC and DEP as the activities performed benefit SC equally.
South Carolina	153865	SC State Gov't Affairs	Carolinas (DEP)	43%	8%		
Ohio	200252	State President OH/KY Staff	Ohio - Elect.	45%	15%		Direct from Validated Survey
Ohio	200252	State President OH/KY Staff	Ohio - Gas	35%	5%		

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Appendix E: Labor Survey Results by Resource

Continued

Jurisdiction	Employee ID #	Responsibility Center	Business Unit's Utility	Survey AC 426	Survey AC 920	Survey Other	Comments / Notes
Federal	227322	Governmental Affairs - Federal	DEBS - FED		55%		Direct from Validated Survey
Florida	227322	Governmental Affairs - Federal	DEBS - FLA		10%		
Indiana	227322	Governmental Affairs - Federal	DEBS - IND		5%		
Kentucky	227322	Governmental Affairs - Federal	DEBS - KY ELE		4%		Account 920 jurisdictional split between KY - ELE and GAS is 80/20 per Survey validation
Kentucky	227322	Governmental Affairs - Federal	DEBS - KY GAS		1%		
North Carolina	227322	Governmental Affairs - Federal	DEBS - NC DEC		5%		Direct from Validated Survey
North Carolina	227322	Governmental Affairs - Federal	DEBS - NC DEP		5%		
Ohio	227322	Governmental Affairs - Federal	DEBS - OH ELE		3%		Account 920 splits based on direct survey results from respondent surveys representing a 63% / 37% split for OH ELE and OH GAS
Ohio	227322	Governmental Affairs - Federal	DEBS - OH Gas		2%		
South Carolina	227322	Governmental Affairs - Federal	DEBS - SC DEC		5%		Direct from Validated Survey
South Carolina	227322	Governmental Affairs - Federal	DEBS - SC DEP		5%		
Federal	265672	Governmental Affairs - Federal	DEBS - FED	70%	30%		Direct from Validated Survey
North Carolina	284280	NC/SC State Gov't Affairs	Carolinas (DEC)	35%	15%		Direct from Validated Survey for DEC and DEP
North Carolina	284280	NC/SC State Gov't Affairs	Carolinas (DEP)	35%	15%		
Florida	327502	External Relations	Florida		100%		Direct from Validated Survey
North Carolina	332591	Environmental Affairs	Carolinas (DEC)	30%	20%		Direct from Validated Survey for DEC and DEP
North Carolina	332591	Environmental Affairs	Carolinas (DEP)	30%	20%		
South Carolina	338568	Government Affairs - SC	Carolinas (DEC)		100%		Direct from Validated Survey
Florida	352084	State President - FL Staff	Florida	55%	45%		Direct from Validated Survey
Federal	354241	Governmental Affairs - Federal	DEBS - FED	60%	40%		Direct from Validated Survey
Florida	354392	State President - FL Staff	Florida	70%	30%		Direct from Validated Survey
Florida	358441	State President - FL Staff	Florida	90%	10%		Direct from Validated Survey
Florida	358442	External Relations	Florida	15%	85%		Direct from Validated Survey
Indiana	359638	Indiana President Staff	Indiana	50%	50%		Direct from Validated Survey
Federal	364786	Governmental Affairs - Federal	DEBS - FED	50%	50%		Direct from Validated Survey
North Carolina	365161	NC/SC State Gov't Affairs	Carolinas (DEC)	43%	8%		Direct from Validated Survey for DEC and DEP
North Carolina	365161	NC/SC State Gov't Affairs	Carolinas (DEP)	43%	8%		
Indiana	365544	Government Affairs - IN	Indiana	50%	50%		Direct from Validated Survey
Federal	367150	Governmental Affairs - Federal	DEBS - FED	50%	50%		Direct from Validated Survey
North Carolina	442750	NC/SC State Gov't Affairs	Carolinas (DEC)	38%	13%		Validated Survey noted a 50/50 split between DEC and DEP
North Carolina	442750	NC/SC State Gov't Affairs	Carolinas (DEP)	38%	13%		
Federal	443371	Governmental Affairs - Federal	DEBS - FED	75%	25%		Direct from Validated Survey
Federal	448281	Governmental Affairs - Federal	DEBS - FED	60%	40%		Direct from Validated Survey
Federal	451589	Governmental Affairs - Federal	DEBS - FED	75%	25%		Direct from Validated Survey

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Feb 18 2020

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.

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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

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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.

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

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

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

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

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

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

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

Education

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

Awards

National Edison Award for Utility Innovations, 2006.

Stephens Exhibit -2

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-4

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.

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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NCJC
Data Request No. 4
DEC Docket No. E-7, Sub1214
Item No. 4-6

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.

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

Docket No. E-7, Sub 1214

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

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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

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Feb 18 2020

NCSEA
Data Request No. 3
DEC Docket No. E-7, Sub 1214
Item No. 3-32

Request:

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

Response:

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

Stephens Exhibit -5

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Feb 18 2020

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

Docket No. E-7, Sub 1214

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

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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

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NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-33

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.

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Feb 18 2020

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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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

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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”.

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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NCJC
Data Request No. 5
DEC Docket No. E-7, Sub1214
Item No. 5-40

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

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removed the Fast Trip settings from the upstream reclosing device, we would still need the transformer fuse to address the primary goals of transformer retrofit to mitigate the number of customers impacted by a sustained fault at the transformer.
c. Momentary benefits from Transformer Retrofit and Targeted Underground are not duplicated because we will not retrofit overhead transformers in the areas that are currently targeted to be converted to underground. Momentary benefits from Transformer Retrofit and Self-Optimizing Grid are not duplicated because the momentaries associated with Transformer Retrofit are only those caused by faults that occur on the transformer. The momentary benefits for SOG are associated with the outages that occur on the 3-phase switchable segments of the circuit.

Stephens Exhibit -8

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

Docket No. E-7, Sub 1214

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

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

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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NCJC
Data Request No. 2
DEC Docket No. E-7, Sub1214
Item No. 2-4
Page 1 of 1

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

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

Docket No. E-7, Sub 1214

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

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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.

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Senior Counsel
Duke Energy Carolinas

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

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.

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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.

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INDEX OF EXHIBITS

Exhibit No.	Description
KGS 1	Curriculum vitae
KGS 2	DEC Response to Tech Customers Data Request 4-17 (including select printouts of "McManeus Grid Deferral Estimate Spreadsheet.")
KGS 3	DEC Response to Tech Customers Data Request 4-5
KGS 4	DEC Response to Tech Customers Data Request 6-9
KGS 5	DEC Response to Tech Customers Data Request 6-1
KGS 6	DEC Response to Tech Customers Data Request 6-2
KGS 7	DEC Response to Tech Customers Data Request 6-18
KGS 8	DEC Response to Tech Customers Data Request 6-19
KGS 9	DEC Response to Tech Customers Data Request 8-2
KGS 10	DEC Response to Tech Customers Data Request 10-2
KGS 11	DEC Response to Tech Customers Data Request 6-5
KGS 12	DEC Response to Tech Customers Data Request 6-15
KGS 13	DEC Response to Tech Customers Data Request 6-11
KGS 14	DEC Response to Tech Customers Data Request 6-12
KGS 15	DEC Response to Tech Customers Data Request 9-2
KGS 16	DEC Response to Tech Customers Data Request 2-1
KGS 17	**[CONFIDENTIAL]** "Cliffside Unit 5, Strategy Update"
KGS 18	**[CONFIDENTIAL]** "Allen Station Retirement Options"
KGS 19	**[CONFIDENTIAL]** DEC Response to Tech Customers Data Request 7-2
KGS 20	DEC Response to Tech Customers Data Request 9-4 (including printout of "2019 DEC NC TC 9-4a&b")
KGS 21	**[CONFIDENTIAL]** DEC Response to Tech Customers Data Request 3-27 (including printout of "CONFIDENTIAL 2019 DEC NC Tech Customer DR3-27f")
KGS 22	EDIT Flowback Survey

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Docket No. E-7, Sub 1214

Tech Customers
Strunk Exhibit KGS 1

Kurt Strunk Qualifications and Experience

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NERA
ECONOMIC CONSULTING

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KURT G. STRUNK
Director

Mr. Strunk is an expert in applied finance and energy matters with over 25 years of experience in international arbitration, complex commercial litigation, and regulatory proceedings. Mr. Strunk is recommended as a leading energy expert by *Who's Who Legal*. He has been retained as an expert to testify in arbitrations, before the Federal Energy Regulatory Commission, US Tax Court, US Federal Court, and US Bankruptcy Court, the National Energy Board in Canada, as well as state and provincial public utilities boards in the US and Canada. His testimonies have addressed construction delay, asset and contract valuation, breach-of-contract damages, the proportionality of stipulated liquidated damages provisions, cost of capital and discount rates, just and reasonable rates, regulatory accounting, prudence, cost of service, regulatory reform, pipeline access, retail market issues, as well as trading and risk management.

In electric power, Mr. Strunk has advised governments, regulators, and energy companies on industry structure, regulation, and sector reform in North America, South America, Europe, Australia, Asia and Africa. In generation, his assignments often involve analysis of new power generation resources and contracts. He has advised on the development of independent power contracts, fuel supply arrangements and competitive solicitations across the globe. He served as a key member of NERA's team advising on electric sector reform and power market design in Mexico, a project he carried out in the Spanish language. He routinely values electricity sector companies and assets in the context of disputes and advisory assignments.

In the oil and gas sectors, Mr. Strunk has consulted on rate matters, mergers and acquisitions, restructurings, contract disputes, valuation and product pricing. He has valued oil and gas assets and contracts in litigated disputes on behalf of major firms in the petroleum sector. He advised sellers of LNG in disputes with buyers (prior to international arbitration) and performed extensive quantitative analysis around appropriate prices and damages in the event of breach. He has served as an expert in regulatory hearings relating to pipeline tariffs in Canada and the United States. He has also carried out studies of the reasonableness of gas supply agreements in various jurisdictions and quantified damages in connection with the early termination of such agreements.

Mr. Strunk's assignments often require that he determines the appropriate return on equity capital for energy firms. He has calculated and supported required rates of return for power generators, gas distribution utilities, electric distribution and transmission companies, and other energy firms in the context of traditional tariff reviews for regulated entities, litigation and advisory work. Mr. Strunk frequently collaborates with NERA's Securities and Finance Practice. He has addressed liability and damages in broker-dealer disputes, and in securities class actions.

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Education

1997	**INSEAD (The European Institute of Business Administration), Fontainebleau, France** MBA, with Distinction, 1997
1993	**VASSAR COLLEGE,** **New York, USA** B.A., Economics, General and Departmental Honors

Career Details

2017-present	**NERA ECONOMIC CONSULTING** Director, New York
2012–2016	**NERA ECONOMIC CONSULTING** Vice President, New York
2005–2012	**NERA ECONOMIC CONSULTING** Senior Consultant, New York
2003–2004	**NERA ECONOMIC CONSULTING** Outside Consultant, New York
2000–2002	**NERA ECONOMIC CONSULTING** Senior Consultant, New York
1998–1999	**NERA ECONOMIC CONSULTING** Senior Analyst, New York
1996	**NERA ECONOMIC CONSULTING** Associate Analyst, New York
1994–1995	**NERA ECONOMIC CONSULTING** Research Associate, New York
1993–1994	**NERA ECONOMIC CONSULTING** Research Assistant, New York
1992	**GÉNÉRALE DE BANQUE** Research Assistant, Brussels

Languages

English:	mother tongue
French:	fluent
Spanish:	fluent

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Project Experience

EXPERT TESTIMONY

2019 **Municipal Light & Power, Chugach Electric Association, Inc. Acquisition**

Oral Testimony before the Regulatory Commission of Alaska on behalf of Chugach Electric Association, Inc., addressing the acquisition of Municipal Light & Power by Chugach Electric and post-acquisition tariff structures. November 5, 2019.

2019 **Southwestern Electric Power Company**
Prudence of Investment in Power Generation Facilities

Sur-Surrebuttal testimony before the Arkansas Public Service Commission on behalf of Southwestern Electric Power Company addressing the prudence of certain investments in power generation facilities. October 2, 2019.

2019 **Central Maine Power Company**
Marginal Cost Study

Oral Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018 Distribution Rate Case, addressing time-of-use pricing, marginal cost estimation and cost recovery for distribution network investment. October 2, 2019.

2019 **NV Energy**
Cost of Capital

Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric division. September 19, 2019.

2019 **Municipal Light & Power, Chugach Electric Association, Inc. Acquisition**

Oral Testimony before the Regulatory Commission of Alaska on behalf of Chugach Electric Association, Inc., addressing the acquisition of Municipal Light & Power by Chugach Electric. September 5 & 6, 2019.

2019 **Corporate Commission of Arizona**

Oral Testimony on behalf of Grand Canyon State Electric Cooperative Association, Inc. before the Corporate Commission of Arizona towards contracts with Qualifying Facilities. August 27, 2019.

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2019 **Central Maine Power Company**
Cost Study for Electric Distributor
Surrebuttal Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018 Distribution Rate Case, addressing the theory of electric utility costing and the implementation of a cost study for the distribution network. August 22, 2019.

2019 **Municipality of Anchorage (ML&P), Chugach Electric Association**
Reasonableness of Proposed Merger
Reply Testimony Before the Regulatory Commission of Alaska addressing the acquisition of Municipal Light & Power by Chugach Electric. August 2, 2019.

2019 **Chugach Electric Associate Inc.**
Cost of Capital
Oral Testimony Before the Regulatory Commission of Alaska addressing the cost of capital for Chugach Electric. July 15, 2019.

2019 **NV Energy**
Cost of Capital
Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric division. June 3, 2019.

2019 **Avangrid NY**
Marginal Cost Study
Direct Testimony before the New York State Public Service Commission on behalf of New York State Electric & Gas Corporation, providing marginal cost estimates for purposes of informing reasonable electric and gas distribution rates. May 20, 2019.

2019 **Avangrid NY**
Marginal Cost Study
Direct Testimony before the New York State Public Service Commission on behalf of Rochester Gas & Electric Corporation, providing marginal cost estimates for purposes of informing reasonable electric and gas distribution rates. May 20, 2019.

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2019 **Central Maine Power Company**
Marginal Cost Study
Rebuttal Testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company in its 2018 Distribution Rate Case, addressing time-of-use pricing, marginal cost estimation and cost recovery for distribution network investment. April 25, 2019.

2019 **Municipality of Anchorage (ML&P), Chugach Electric Association**
Reasonableness of Proposed Merger
Pre-filed direct testimony on behalf of Chugach Electric Association, Inc. before the Regulatory Commission of Alaska supporting Chugach's proposed acquisition of ML&P from the Municipality of Anchorage. Testimony addresses the valuation of ML&P, the reasonableness of the purchase price, forecast synergy savings, market pricing for a related Power Purchase Agreement, and the tangible benefits that will accrue to ratepayers as a result of the merger. April 1, 2019.

2019 **Public Service Company of New Mexico**
Reasonableness of Power Purchase Agreement
Affidavit before the Federal Energy Regulatory Commission including a benchmarking analysis of a solar power purchase agreement under FERC's *Edgar* and *Ocean States* standards. March 15, 2019.

2019 **NV Energy**
Cost of Gas / Prudence
Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas purchases. March 1, 2019.

2019 **Southwestern Electric Power Company**
Prudence of Investment in Power Generation Facilities
Direct Testimony before the Arkansas Public Service Commission on behalf of Southwestern Electric Power Company addressing the prudence of the company's investments in the Dolet Hills Power Plant. February 28, 2019.

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2018 **PacifiCorp**
Cost of Capital
Rebuttal Testimony before the California Public Utilities Commission, on behalf of PacifiCorp, on the cost of capital in the Company's rate case, November 20, 2018.

2018 **LS Power Company**
Generation Capacity Market Design
Reply Affidavit (w/Willis Geffert), on behalf of LS Power Associates, L.P., before the Federal Energy Regulatory Commission, addressing flaws in the existing capacity market construct in the PJM Interconnection. November 6, 2018

2018 **LS Power Company**
Generation Capacity Market Design
Affidavit (w/Willis Geffert), on behalf of LS Power Associates, L.P., before the Federal Energy Regulatory Commission, addressing flaws in the existing capacity market construct in the PJM Interconnection. October 2, 2018.

2018 **Maui Electric Company**
Power Generation Costs, Incentives, Fuel Adjustment Clauses
Rebuttal Testimony before the Hawai'i Public Utilities Commission on behalf of Maui Electric Company, Inc., addressing matters pertaining to its fuel costs and Energy Cost Adjustment Clause, June 22, 2018.

2018 **PacifiCorp**
Cost of Capital
Direct Testimony before the California Public Utilities Commission, on behalf of PacifiCorp, on the cost of capital in the Company's rate case, April 12, 2018.

2018 **Hawaiian Electric Company**
Power Generation Costs, Incentives, Fuel Adjustment Clauses
Affidavit before the Hawai'i Public Utilities Commission on behalf of Hawaiian Electric Company, Inc., addressing matters pertaining

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to Hawaiian Electric's Energy Cost Adjustment Clause, April 10, 2018.

2018 **North Carolina Utilities Commission Raleigh**
Tax, Regulatory and Utility Financial Matters
Supplemental testimony before the State of North Carolina Utilities Commission Raleigh, presenting opinions on various tax, economic, regulatory and financial matters in the Duke Energy Carolinas General Rate Case, March 20, 2018.

2018 **Hawaiian Electric Company**
Power Generation Costs, Incentives, Fuel Adjustment Clauses
Supplemental Testimony before the Public Utilities Commission of Hawaii, presenting opinions on fuel costs and energy cost adjustment clauses, February 14, 2018.

2018 **North Carolina Utilities Commission Raleigh**
Regulation and Utility Finance
Pre-filed testimony before the State of North Carolina Utilities Commission Raleigh, presenting opinions on various economic, regulatory and financial matters in the Duke Energy Carolinas General Rate Case, January 23, 2018.

2018 **Hawaiian Electric Company**
Power Generation, Incentive Ratemaking, Fuel Adjustment Clauses
Rebuttal Testimony before the Public Utilities Commission of Hawaii, addressing fuel costs and the appropriateness of the current and proposed Energy Cost Adjustment Clause ("ECAC"), January 05, 2018.

2017 **Nevada Power Company**
Cost of Capital
Oral testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company presenting his analysis and conclusions on the cost of capital. November 1, 2017.

2017 **Energía Limpia de Guatemala, S.A.**
EPC Contracts, Liquidated Damages, Power Industry Practices
Oral Testimony before the ICC Court of Arbitration, ICC Case No. 21361/RD, on behalf of Energía Limpia de Guatemala, S.A., addressing

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the proportionality of liquidated damages in a turnkey EPC contract, October 25, 2017.

2017 **Nevada Power Company**
Cost of Capital
Rebuttal testimony before the Public Utilities Commission of Nevada on behalf of Nevada Power Company presenting on the cost of capital, September 26, 2017.

2017 **Energía Limpia de Guatemala, S.A.**
EPC Contracts, Liquidated Damages, Power Industry Practices
Pre-filed Expert Report before the ICC Court of Arbitration (w/Willis Geffert), ICC Case No. 21361/RD, on behalf of Energía Limpia de Guatemala, S.A., addressing the proportionality of liquidated damages in a turnkey EPC contract, September 15, 2017.

2017 **Hawai'i Electric Light**
Power Generation, Incentive Ratemaking, Fuel Adjustment Clauses
Rebuttal Testimony before the Hawai'i Public Utilities Commission, on behalf of Hawai'i Electric Light, addressing alternative incentive mechanisms for the Company's power generation fleet, fuel costs, and the reasonableness of the Company's proposed ECAC, June 23, 2017.

2017 **Southwestern Electric Power Company**
Prudence of Investment in Power Generation Facilities
Oral Testimony before the Public Utility Commission of Texas on behalf of Southwestern Electric Power Company addressing the prudence of the company's investments in the Dolet Hills Power Plant, June 15, 2017.

2017 **NV Energy**
Cost of Capital
Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, addressing the cost of capital for the Company, June 5, 2017.

2017 **Southwestern Electric Power Company**
Prudence of Investment in Power Generation Facilities
Rebuttal Testimony before the Public Utilities Commission of Texas, on behalf of Southwestern Electric Power Company, addressing the prudence

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of retrofit investments in certain electricity generation facilities, May 19, 2017.

2017 **North Carolina Utilities Commission**
Power Contract Design, Financing New Power Plants
Direct Testimony before the North Carolina Utilities Commission, on behalf of North Carolina Sustainable Energy Association, addressing the biennial determination of avoided cost rates for electric utility purchases from qualifying facilities, March 28, 2017.

2017 **NV Energy**
Cost of Gas / Prudence
Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas purchases, March 1, 2017.

2016 **NV Energy**
Cost of Capital
Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric and gas divisions, September 23, 2016.

2016 **Hawai'i Electric Light**
Power Generation, Incentive Ratemaking, Fuel Adjustment Clauses
Direct Testimony before the Hawai'i Public Utilities Commission, on behalf of Hawai'i Electric Light, addressing alternative incentive mechanisms for the Company's power generation fleet, fuel costs, and the reasonableness of the Company's proposed ECAC, September 19, 2016.

2016 **NV Energy**
Cost of Capital
Certification Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric and gas divisions, August 2, 2016.

2016 **NV Energy**
Cost of Capital
Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, addressing the cost of capital for the Company's electric and gas divisions, June 6, 2016.

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2016 **PacifiCorp**
Cost of Capital
Oral Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital in the Company's expedited rate filing (Docket UE-152253), May 2, 2016.

2016 **Confidential Client**
Damages under Wind Power Purchase Agreement
Expert Report in arbitration on the valuation of damages under a PPA backed by a wind farm, with a particular focus on the reasonableness of the liquidated damages cap, April 25, 2016.

2016 **Municipality of Anchorage (ML&P), Chugach Electric Association**
Valuation of Gas Field and Reasonableness of Acquisition Price
Oral Testimony before the Regulatory Commission of Alaska on the reasonableness of the proposed acquisition of ConocoPhillips' working interest in the Beluga River Unit, April 19, 2016.

2016 **PacifiCorp**
Cost of capital
Rebuttal Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital in the Company's expedited rate filing (Docket UE-152253), April 7, 2016.

2016 **NV Energy**
Cost of Gas / Prudence
Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas purchases, March 1, 2016.

2016 **Alliance to Protect Nantucket Sound**
Financing of off-shore wind farm
Oral Testimony before the Energy Facilities Siting Board of the Commonwealth of Massachusetts on the financeability of the Cape Wind project, January 25, 2016.

2015 **PacifiCorp**
Cost of capital
Direct Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital, November 24, 2015.

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2015 **Chugach Electric Association, Inc.**
Regulatory principles for cost allocation
Oral testimony before the Regulatory Commission of Alaska, addressing the regulatory treatment of gas found by Cook Inlet Natural Gas Storage Alaska LLC, August 31, 2015.

2015 **Baltimore Gas & Electric Company**
Risks and rate of return for retail electricity business
Oral Testimony before the Maryland Public Service Commission, *in the Matter of Baltimore Gas & Electric's Application to Recover Cash Working Capital for Standard Offer Service*, Case No. 9221, August 5, 2015.

2015 **Baltimore Gas & Electric Company**
Risks and rate of return for retail electricity business
Rebuttal Testimony before the Maryland Public Service Commission, *in the Matter of Baltimore Gas & Electric's Application to Recover Cash Working Capital for Standard Offer Service*, Case No. 9221, July 22, 2015.

2015 **Chugach Electric Association, Inc.**
Regulatory principles for cost allocation
Pre-filed testimony before the Regulatory Commission of Alaska, addressing the regulatory treatment of gas found by Cook Inlet Natural Gas Storage Alaska LLC, June 5, 2015.

2015 **ATX Southwest, LLC.**
Cost of Capital
Direct Testimony before the Federal Energy Regulatory Commission, on behalf of ATX Southwest, addressing return on equity, May 28, 2015.

2015 **Chugach Electric Association, Inc.**
Cost of Capital
Responsive Testimony before the Regulatory Commission of Alaska, addressing return on equity for the Enstar Natural Gas Company, May 15, 2015.

2015 **Baltimore Gas & Electric Company**
Risks and rate of return for retail electricity business
Testimony before the Maryland Public Service Commission, *in the Matter of Baltimore Gas & Electric's Application to Recover Cash Working Capital for Standard Offer Service*, Case No. 9221, April 22, 2015.

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2015 **NV Energy**
Cost of Gas / Prudence
Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas purchases, March 1, 2015.

2014 **PacifiCorp**
Cost of capital
Oral Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital in the Company's general rate case, December 16, 2014.

2014 **PacifiCorp**
Cost of capital
Rebuttal Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital in the Company's general rate case, November 21, 2014.

2014 **PacifiCorp**
Cost of capital
Direct Testimony before the Washington Utilities and Transportation Commission, on behalf of PacifiCorp, on the cost of capital in the Company's general rate case, including the effects of transitioning away from coal, April 30, 2014.

2014 **Nevada Power Company**
Cost of capital
Direct Testimony before the Nevada Public Utilities Commission, on behalf of Nevada Power Company, on the cost of capital in the Company's general rate case, April 30, 2014.

2015 **NV Energy**
Cost of Gas / Prudence
Direct Testimony before the Nevada Public Utilities Commission, on behalf of NV Energy, addressing the reasonableness of the Company's natural gas purchases, March 1, 2014.

2013 **Sierra Pacific Power Company**
Cost of capital
Oral testimony, before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, on the cost of capital for the gas and electric divisions in the Company's general rate case, October 7, 2013.

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2013 **Sierra Pacific Power Company**
Cost of capital
Rebuttal Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, on the cost of capital for the gas and electric divisions in the Company's general rate case, September 25, 2013.

2013 **Market Area Shippers**
(Gaz Métro, Union Gas and Enbridge Gas Distribution)
Contract Renewal Alternatives for Regulated Pipeline Service
Pre-filed Expert Report, with Jeff Makholm, before the National Energy Board of Canada, in the Matter of TransCanada's Application for Tariff Amendments, Hearing Order RH-001-2013, July 26, 2013.

2013 **Sierra Pacific Power Company**
Cost of capital
Direct Testimony before the Nevada Public Utilities Commission, on behalf of Sierra Pacific Power Company, on the cost of capital for the gas and electric divisions in the Company's general rate case, June 4, 2013.

2013 **NV Energy Operating Companies**
Cost of capital
Direct Testimony before the Federal Energy Regulatory Commission, on behalf of NV Energy Operating Companies, on the appropriate rate of return for the consolidated transmission system, May 31, 2013.

2013 **Public Intervenor**
Wholesale Margins for Regulated Motor Fuels and Heating Oil
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of an Application by Irving Oil Marketing GP and Irving Oil Commercial GP requesting an increase in the wholesale margins for motor fuels and heating oil*, January 29, 2013.

2013 **Public Intervenor**
Power sector modelling, deferral account policy, financial analysis
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of the Point Lepreau Nuclear Generating Station Deferral Account and Section 143.1 of the Electricity Act*, January 15, 2013.

2012 **Baltimore Gas & Electric Company**
Potomac Electric Power Company
Power Purchase Agreements, Retail electric competition
Oral testimony before the Maryland Public Service Commission *In the Matter of Whether New Generation Resources Are Needed to Meet Long-*

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Term Demand for Standard Offer Service, Case No. 9214, November 26, 2012.

2012 **Public Intervenor**

Modelling of coal and oil plants, deferral account, financial analysis

Pre-filed Expert Report before the New Brunswick Energy and Utilities Board *In the Matter of the Point Lepreau Nuclear Generating Station Deferral Account and Section 143.1 of the Electricity Act*, November 26, 2012.

2012 **Nevada Power Company**

Cost of capital

Pre-filed testimony before the Federal Energy Regulatory Commission in the Nevada Power Company's Transmission Rate Case, October 31, 2012.

2012 **Public Intervenor**

Wholesale margins for regulated motor fuels and heating oil

Pre-filed Expert Report before the New Brunswick Energy and Utilities Board In the Matter of an Application by Irving Oil Marketing G.P. and Irving Oil Commercial G.P. Requesting an Increase in the Wholesale Margins for Motor Fuels and Heating Oil, October 26, 2012.

2012 **Nevada Power Company**

Prudence of gas costs for 2012

Pre-filed Expert Report before the Nevada Public Utilities Commission *In the Nevada Power Company's 2012 Deferred Energy Filing*, March 1, 2012.

2012 **Sierra Pacific Power Company**

Prudence of gas costs for 2012

Pre-filed Expert Report before the Nevada Public Utilities Commission *In the Nevada Power Company's 2012 Deferred Energy Filing*, March 1, 2012.

2011 **Public Intervenor**

Power system loss factors, OATT, transmission regulatory policy

Pre-filed Expert Report before the New Brunswick Energy and Utilities Board *In the Matter of a Review of the Proposed Change to the New Brunswick System Operator's Real Power Loss Fact*or, October 31, 2011.

2011 **John Hancock**

Risk analysis of European power plant leveraged lease

Oral Testimony before the U.S. Tax Court, on behalf of plaintiff in *John Hancock Life Insurance Company and Subsidiaries v. Commissioner of Internal Revenue*, October 24, 2011.

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2011 **John Hancock**
Risk analysis of European power plant leveraged lease
Rebuttal Expert Report before the U.S. Tax Court, on behalf of plaintiff in *John Hancock Life Insurance Company and Subsidiaries v. Commissioner of Internal Revenue*, August 19, 2011.

2011 **John Hancock**
Risk analysis of European power plant leveraged lease
Pre-filed Expert Report before the U.S. Tax Court on behalf of plaintiff in *John Hancock Life Insurance Company and Subsidiaries v. Commissioner of Internal Revenue*, July 8, 2011.

2011 **Public Intervenor**
OATT, transmission regulatory policy
Pre-filed Expert Report before the New Brunswick Energy and Utilities Board, *in the Review of the Proposed Changes to the New Brunswick System Operator's Open Access Transmission Tariff*, February 21, 2011.

2011 **Public Intervenor**
Power system loss factor, OATT, transmission regulatory policy
Pre-filed Expert Report before the New Brunswick Energy and Utilities Board, *in the Review of the New Brunswick System Operator's Proposed Change to its Loss Factor*, February 3, 2011.

2011 **Baltimore Gas & Electric Company**
Risks and rate of return for retail electricity business
Oral testimony before the Maryland Public Service Commission, *in the Matter of Baltimore Gas & Electric's Application to Recover Cash Working Capital for Standard Offer Service*, Case No. 9221, January 20, 2011.

2010 **Baltimore Gas & Electric Company**
Risks and rate of return for retail electricity business
Pre-filed Expert Report before the Maryland Public Service Commission, *in the Matter of Baltimore Gas & Electric's Application to Recover Cash Working Capital for Standard Offer Service*, Case No. 9221, September 17, 2010.

2010 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Oral testimony before the New Brunswick Energy & Utilities Board, in the *Enbridge Gas New Brunswick Rate Case,* March 30, 2010.

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2010 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Pre-filed Expert Report before the New Brunswick Energy and Utilities Board, *in the Matter of Enbridge Gas New Brunswick Rate Case*, March 12, 2010.

2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Oral testimony before the New Brunswick Energy & Utilities Board, *in the Review of Matters related to the Regulation of Enbridge Gas New Brunswick*, October 23, 2009.

2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Pre-filed Expert Report before the New Brunswick Energy and Utilities Board, *in the Matter of the Annual Financial Review of Enbridge Gas New Brunswick Limited Partnership*, August 21, 2009.

2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Oral testimony before the New Brunswick Energy and Utilities Board, *in the Matter of the Annual Financial Review of Enbridge Gas New Brunswick Limited Partnership*, September 15, 2009.

2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Pre-filed Expert Report before the New Brunswick Energy and Utilities Board*, in the Matter of a Review of Matters Related to the Regulation of Enbridge Gas New Brunswick Limited Partnership*, September 21, 2009.

2009 **The City of New York**
Cost of service, incentives and taxi lease rates
Oral testimony in the District Court for the Southern District of New York in *Metropolitan Taxicab Board of Trade et al. v. The City of New York et al.,* on the issue of whether the Taxi and Limousine Commission's new maximum lease rates constitute a fuel efficiency and emissions mandate that would be preempted by Federal law, May 20, 2009.

2009 **The City of New York**
Cost of service, incentives and taxi lease rates
Pre-filed expert Report in the United States District Court for the Southern District of New York in *Metropolitan Taxicab Board of Trade et al. v. The City of New York et al.,* on the issue of whether the Taxi and Limousine Commission's new maximum lease rates constitute a fuel efficiency and emissions mandate that would be preempted by Federal law, May 18, 2009.

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2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of the examination of the formula for Enbridge Gas New Brunswick's market-based rate,* April 23, 2009.

2009 **Public Intervenor**
Greenfield gas distributor, cost of service, just and reasonable rates
Pre-filed Report before the New Brunswick Energy and Utilities Board, *In the Matter of the examination of the formula for Enbridge Gas New Brunswick's market-based rate,* March 26, 2009.

2009 **Public Intervenor**
Cost of service, ISO management, OATT transmission policy
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of the application of the New Brunswick System Operator for changes to its Charges, Rates and Tolls,* March 18, 2009.

2009 **Public Intervenor**
Cost of service, ISO management, OATT transmission policy
Pre-filed Report before the New Brunswick Energy and Utilities Board, *In the Matter of the application of the New Brunswick System Operator for changes to its Charges, Rates and Tolls,* February 24, 2009.

2008 **Allegheny Power, Baltimore Gas & Electric**
Integrated resource planning, competitive retail electric markets
Oral testimony before the Maryland Public Service Commission, *in the Matter of the Commission's Investigation Of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, December 15, 2008.

2008 **Allegheny Power, Baltimore Gas & Electric**
Integrated resource planning, competitive retail electric markets
Pre-filed Report before the Maryland Public Service Commission, *in the Matter of the Commission's Investigation Of Investor-Owned Electric Companies' Standard Offer Service for Residential and Small Commercial Customers in Maryland*, Case No. 9117, October 1, 2008.

2008 **Public Intervenor**
Ratemaking for greenfield gas distributor
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of an application by Enbridge Gas New Brunswick for changes to its Charges, Rates and Tolls,* March 27, 2008.

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2008 **Public Intervenor**

Ratemaking for greenfield gas distributor
Pre-filed Report before the New Brunswick Energy and Utilities Board, *In the Matter of an application by Enbridge Gas New Brunswick for changes to its Charges, Rates and Tolls,* March 10, 2008.

2007 **Public Intervenor**

Prudence, just and reasonable standard, affiliate transactions
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls,* December 18, 2007.

2007 **Public Intervenor**

Nuclear power plant Cost of Service
Pre-filed Report before the New Brunswick Board of Commissioners of Public Utilities, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls,* December 7, 2007.

2007 **Public Intervenor**

Prudence of power generation costs
Pre-filed Report before the New Brunswick Board of Commissioners of Public Utilities, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls,* November 5, 2007.

2007 **Public Intervenor**

Prudence of power generation costs
Oral testimony before the New Brunswick Energy and Utilities Board, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls,* June 21, 2007.

2007 **Public Intervenor**

Prudence of power generation costs
Pre-filed Report before the New Brunswick Energy and Utilities Board, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls,* June 14, 2007.

2006 **Brookfield Energy Marketing Inc.**

Valuation of power purchase agreement and power plant

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Deposition testimony before the United States Bankruptcy Court for the District of Maryland, on behalf of Brookfield Energy Marketing Inc., *In re: USGen New England, Inc.*, Debtor, Case No. 03-30465, May 22, 2006.

2006 **Brookfield Energy Marketing Inc.**
Valuation of power purchase agreement and power plant
Rebuttal Report before the United States Bankruptcy Court for the District of Maryland, on behalf of Brookfield Energy Marketing Inc., *In re: USGen New England, Inc.*, Debtor, Case No. 03-30465, May 5, 2006.

2006 **Brookfield Energy Marketing Inc.**
Valuation of power purchase agreement and power plant
Expert Report before the United States Bankruptcy Court for the District of Maryland, on behalf of Brookfield Energy Marketing Inc., *In re: USGen New England, Inc.*, Debtor, Case No. 03-30465, March 29, 2006.

2006 **Public Intervenor**
Application of the prudence standard to affiliate transactions
Oral testimony before the New Brunswick Board of Commissioners of Public Utilities, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls*, March 14, 2006.

2006 **Public Intervenor**
Application of the prudence standard to affiliate transactions
Pre-filed Report with Eugene Meehan before the New Brunswick Board of Commissioners of Public Utilities, *In the Matter of an application by the NBP Distribution & Customer Service Corporation (Disco) for changes to its Charges, Rates and Tolls*, January 31, 2006.

2005 **Dayton Power & Light Company**
Retail pricing for default service customers and option valuation
Oral testimony at hearings in Ohio Public Utilities Commission Case No. 05-276-EL-AIR, November 8 and 14 2005.

2005 **Dayton Power & Light Company**
Retail pricing for default service customers and option valuation
Deposition testimony in Ohio Public Utilities Commission Case No. 05-276-EL-AIR, November 8, 2005.

2005 **Dayton Power & Light Company**
Retail pricing for default service customers and option valuation
Testimony in Ohio Public Utilities Commission, in Support of Stipulation filed in support of Dayton's proposed settlement Case No. 05-276-EL-AIR, November 4, 2005.

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2005 **Dayton Power & Light Company**
Retail pricing for default service customers and option valuation
Rebuttal testimony in Ohio Public Utilities Commission, application of financial options pricing techniques to assess the reasonableness of Dayton's proposed provider-of-last-resort charges, Case No. 05-276-EL-AIR, October 31, 2005.

2004 **Board of Public Utilities**
Cost of capital
Pre-filed testimony with Cindy Ma before the Board of Public Utilities, Newfoundland and Labrador, Canada, on "The Cost of Capital for Automobile Insurance Firms," October 13, 2004.

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CONSULTING EXPERT EXPERIENCE

2019 — **Confidential Client**
Financial Structure Analysis
Expert in dispute related to the financial structure of assets owned by a midstream oil and products company.

2016 — **Confidential Client**
Valuation of Solar Generation Facilities
Expert in dispute related to the valuation of rooftop solar facilities. Provided valuation options to counsel to evaluate the reasonableness of the claimed tax basis and Section 1603 cash grant.

2014 — **Confidential Client**
Offshore Exploration and Production Permit Arbitration
Expert in dispute related to an agreement between two firms to develop an offshore gas field in New Zealand in arbitration at the ICC International Court of Arbitration.

2014 — **Confidential client**
Breach of contract damages valuation for gas supply agreement
Valued damages in a breach-of-contract dispute regarding gas supply in Western Australia.

2013–Present — **Gaz Métro**
Cost Recovery of Gas Distribution System Upgrade
Advised client on regulatory merits of ratemaking for distribution system upgrade. Performed survey of ratemaking policies for similar upgrades in other jurisdictions in connection with proceeding before Provincial regulator.

2014-Present — **Confidential Client**
Gas Supply Agreement Negotiation
Advise on cost of service and LNG contract price issues in Western Australia.

2014- Present — **Alliance Pipeline**
Restructuring of services and tolls
Advised on Alliance's restructuring proposal in a matter before the National Energy Board. Supervised modelling of pipeline tolls and assessment of natural gas pipeline market power.

2014-2015 — **Gazprom OAO**
Civil dispute involving gas field development and LNG importation
Supervised modelling of LNG netback prices and damage calculations in preparation for a jury trial before a Tarrant County, Texas District Court. Consulted with respect to a dispute between a U.S oil company and

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Russian oil company regarding ownership of a Russian gas field, tortious interference, and trade secret misappropriation with regards to a plan to import LNG into the United States in the mid-2000s.

2014 **FortisBC Energy Inc**
Tolling for pipeline in Canada
Analyzed toll methodology and advised on regulatory issues related to a tolling proposal of NGTL's North Montney Mainline, an extension of the existing NGTL Alberta System.

2014 **Royal Bank of Canada**
Gas Supply Agreement Dispute
Served as consulting expert in a gas supply agreement dispute between RBC and three municipal gas distributors in Nevada and Iowa. Case involved analysis of Basel III regulations, capital requirements, commodity swaps and interest rate swaps.

2013 **Confidential client**
Valuation and pricing analysis
Performed valuation and pricing analysis for oil pipeline dispute in Texas. Provided advice to outside counsel throughout litigation.

2012-2014 **ATCO Gas & ATCO Electric**
Cost of Service / Capital Trackers
Provided expert review of ATCO Gas and ATCO Electric's capital tracker proposals, including a survey of capital trackers in other jurisdictions.

2012–2013 **Confidential client**
Valuation of oil pipeline company and its hedging positions
Performed valuation of oil pipeline company and its hedging positions in litigation involving an alleged breach of fiduciary duty. Provided advice to outside counsel throughout litigation.

2012–2013 **Confidential client**
Approaches to regulatory accounting and cost-of-service regulation
Contributed to study assessing benefits of various approaches to regulatory accounting and cost-of-service regulation for pipelines.

2011–2013 **Confidential client**
Possible outcomes of power contract (PPA) disputes
Analyzed potential litigation and settlement outcomes in a series of power contract disputes. Provided advice to outside counsel.

2011–2012 **Confidential client**
Oil pipeline cost of service and depreciation policies

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Advised counsel to a shipper in an intrastate oil pipeline company rate case before the Kansas Corporation Commission.

2011 **Confidential client**

Antitrust aspects of a proposed pipeline merger

Analyzed antitrust aspects of oil pipeline combinations in connection with a proposed merger. Provided advise to outside counsel.

2010–2011 **Confidential client**

Valuation of generation assets

Performed valuation of power plant in context of alleged expropriation.

2010 **Hydro Québec, Canada**

Grid connection and upgrade cost policy

Analyzed grid connection and upgrade cost policy. Evaluated existing policy to allocate costs of grid upgrades to generation developers and system users. Suggested modifications to policy. Prepared benchmarking analysis comparing the company's practices to those of over a dozen other entities in North America.

2008 **Confidential client**

Allegations of energy market manipulation

Advised on the evaluation of allegations of energy market manipulation in the context of physical electricity trades in RTO-managed markets.

2007 **Confidential client**

Valuation of valuation of long-dated oil warrants

Performed valuation of long-dated oil warrants priced off Venezuelan crude oil in context of damages calculation.

2006 **Confidential client**

Damages valuation in securities class action

Valued damages in a securities class action related to the bankruptcy of an energy retailer.

2003-2004 **Confidential client**

Bid process advantages: generation pricing and transmission costs

Contributed to testimony on behalf of a large electric utility regarding an affiliate transaction that resulted from a competitive solicitation. Testimony before FERC focused on whether the affiliate was advantaged during the bid process, both with respect to generation pricing and electric transmission cost.

2003 **Confidential client**

Valuation, economic, accounting, and hedging analysis

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Performed valuation, economic, accounting, and hedging analysis of a gas-fired power plant in an international arbitration matter.

2002 **Confidential client**

Prudence of forward power purchases

Contributed to testimony on behalf of an electric utility regarding the prudence of forward power purchases during the Western power crisis.

2002–2003 **Pacific Gas & Electric**

Valuation of Damages Due to Gas Pipeline Capacity Withholding

Performed analyses of damages from withheld pipeline capacity into California. Analyses led to $1 billion settlement.

2002–2003 **Confidential client**

Prudence of forward power purchases

Contributed to testimony regarding the prudence of Department of Water Resources's forward power purchases during the Western power crisis.

2002 **Confidential client**

Electric and gas hedging strategies for its generation assets

Contributed to testimony on behalf of an energy marketing and trading firm regarding electric and gas hedging strategies for its generation assets, including an examination of the nature of competition among energy marketing and trading firms and strategies.

2001–2002 **Pacific Gas & Electric Company**

FERC refund and other related proceedings

Analysis and support to a California utility in the context of the FERC refund and other related proceedings, 2001-2002.

2001–2002 **Pacific Gas & Electric Company**

Value of a long-term affiliate power sales agreement

Contributed to testimony before FERC relating to the value of a long-term affiliate power sales agreement. Involved analysis and valuation of over 100 long-term power contracts (PPAs) in the context of this benchmarking analysis.

2001 **Confidential client**

Valuation of a passive equity interest

Contributed to testimony on behalf of a leading US energy company regarding the valuation of a passive equity interest in an IPP project in El Salvador.

2001 **Baltimore Gas & Electric Company**

Business separation of Constellation Energy Group

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Contributed to testimony submitted to the Public Service Commission of Maryland on the business separation of Constellation Energy Group.

1998 **Baltimore Gas & Electric Company**

Valuation of generation assets

Performed valuation of Baltimore Gas & Electric Company's hydro, nuclear, coal and gas-fired generation assets in the context of stranded cost calculations during restructuring, 1998.

1995–1996 **Confidential client**

Analysis of market concentration

Performed HHI analyses to support testimony presenting a competitive assessment of the Western electric generation market in the US, 1995-1996.

1994–1995 **Confidential client**

Damages valuation in securities class action

Estimated losses and alleged damages for several mutual funds that invested in derivative securities.

1994–1995 **Confidential client**

Damages valuation in securities class action

Estimated losses and alleged damages for several mutual funds that invested in derivative securities.

1994 **Goldman Sachs**

Default risk studies on fixed income instruments

Prepared default risk studies on fixed income instruments for counsel to Goldman Sachs in a broker/dealer arbitration.

1994 **Confidential client**

Damages valuation in securities class action

Consulted to counsel for an infomercial company on materiality, liability, and damages in a shareholder class action suit.

1993 **Confidential client**

Damages valuation in securities class action

Assessed materiality and damages in a 10b-5 class action against a major pharmaceutical company.

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ADVISORY PROJECTS

2017-2019 **Valuation of Vertically-Integrated Electric Utility**
Due Diligence for Prospective Acquirer
Retained by an electric utility to advise on valuation of a target utility acquisition. Assisted client in developing reasonable offers to acquire the target electric utility. Advised utility during negotiations.

2017 **Marginal Cost Study for Value of Distributed Resource**
Due Diligence for Prospective Acquirer
Retained by NYSEG and RG&E to perform a marginal cost study to estimate key components of the value stack, to be paid to solar and other distributed energy resources,

2017 **Leveraged Lease tied to Power Plant**
Due Diligence for Prospective Acquirer
Retained by a confidential acquirer to evaluate a target utility-related investment. Provided strategic advice and due diligence relating to the financial valuation and post-acquisition benefits.

2016 **Utility Merger**
Due Diligence on Merger Benefits
Retained by a confidential acquirer to evaluate merger benefits in the context of the combination of two adjacent electric utilities. Provided strategic advice and due diligence relating to merger benefits.

2016 **Wind Power Transaction**
Due Diligence for Prospective PPA Offtaker
Retained by a confidential offtaker to evaluate the costs, benefits and risks associated with a prospective long-term power purchase transaction backed by a wind farm.

2016 **Electric Utility Acquisition**
Due Diligence for Prospective Acquirer
Retained by a confidential equity investor to evaluate key inputs for the acquirer's valuation model of an electric utility. Advised investor on key elements of the valuation.

2015 **Ministry of Energy, Mexico**
Restructuring of the Mexican energy sector
Served as leader for several work streams performed on behalf of the Mexican Ministry of Energy implementing energy sector restructuring. Advice included the design of a competitive spot market, the development of green power auctions (solar and wind), basic service supply pricing, electricity transmission pricing, upstream gas pricing and the development of a regulatory framework for the sector.

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2015 **Southern Star Central Gas Pipeline**
Due Diligence for Prospective Acquirer
Retained by a confidential equity investor to evaluate regulatory and investment risk associated with the prospective acquisition of an interest in Southern Star. Analyzed likely outcomes in the pipeline's upcoming rate case, and their implications for the valuation of the target.

2015 **Independent Electricity System Operator (IESO)**
Reasonableness of 6,300 MW Power Transaction
Retained by IESO in Ontario, Canada, to prepare, together with a team of NERA experts, an Opinion as to the Fairness of the Amended and Restated Bruce Power Refurbishment Implementation Agreement.

2015 **ESKOM, South Africa**
Regulatory Strategy for Cost Recovery
Retained by ESKOM to advise on regulatory strategy, treatment of coal-plant operation and associated fuel costs, delays in unit online dates and other regulatory issues.

2015 **Bermuda Electric, Bermuda**
Regulatory Strategy, Cost of Service, and Tariffs
Advised on regulatory strategy. Developed costing and pricing model for Bermuda Electric.

2014 **Hawaiian Electric Company**
Fuel Adjustment Clause and Oil Hedging
Retained by Hawaiian Electric Company to provide analysis regarding the efficiency incentives embedded in the company's fuel adjustment clause (ECAC). Analyzed the possibility of hedging oil price volatility through commercially-available contracts.

2014 **Confidential Client**
Pricing Principles for Domestic Gas Reservation Policy
Formulated a methodology to determine a schedule of reasonable prices using a cost of service approach for gas that the company is obligated to market under the domestic gas supply policy in Western Australia.

2012/2013 **Atlantic Path 15**
Due Diligence Study for Confidential Potential Buyer
Performed regulatory due diligence in connection with the potential acquisition of Atlantic Path 15 transmission assets. Evaluated the regulatory climate at FERC and analyzed FERC decisions from prior rate cases, with a focus on allowed rate of return. Used NERA rate-of-return models to replicate the FERC methodology and to predict the rate-of-return to be allowed by FERC in the next rate case.

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2013 **Energy trading entity**
Price risks and electricity transmission development
Retained by energy trading entity to perform an independent study of price risks and electricity transmission development in the ERCOT market.

2013 **Electric industry client**
Reactive power compensation
Retained by electric industry client to analyze electricity transmission tariffs and reactive power compensation in competitive electric markets.

2012/2013 **New Mexico Natural Gas Company**
Due Diligence Study for Confidential Acquirer
Performed regulatory due diligence in connection with the potential acquisition of New Mexico Natural Gas. Assessed hurdles to getting the transaction approved by regulatory authorities. Analyzed recent rate actions by the state commission and the likely outcomes of future cases. Advised on key inputs into the acquirer's financial model.

2012 **Oil industry client**
Regulation benchmarking in downstream oil sector
Retained by oil industry client to advise on margins and to perform an international benchmarking of the regulation of the downstream oil sector.

2012 **Hawaiian Electric Company**
Hedging and rate stabilization
Retained by Hawaiian Electric Company to provide analysis regarding hedging of fuel oil and diesel fuel purchases in order to stabilize customer rates.

2011 **Confidential client**
Implications of CFTC proposed definition of swap dealer
Advised on margin, capital and reporting implications of CFTC proposed definition of swap dealer under Dodd Frank.

2010 **Confidential client**
Leveraged lease transaction
Provided litigation support services with respect to a dispute over a leveraged lease transaction.

2010 **Confidential client**
Valuation, risk assessment and analysis of offtake contract options
Performed detailed valuation, risk assessment and analysis of offtake contract options for a hydroelectric power plant.

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2009 **Potomac Edison Company**

Capital investment planning

Performed least-cost capital investment planning on behalf of the Potomac Edison Company.

2009 **Government of New Brunswick, Canada**

Advised on electric utility valuation

Advised Government of New Brunswick on the valuation of the vertically-integrated, provincially-owned electric utility, NB Power, in connection with the potential sale to Hydro Québec. Developed a financial and rate model reflecting the New Brunswick regulatory system and performed valuations for a stand-alone and merged case and performed numerous valuations of the benefits to the acquirer. Developed key inputs for the valuation, including the Point Lepreau Nuclear Generation Station. Coordinated development of fairness opinion.

2009 **Energy East**

Cost of capital

Advised on rate-of-return issues for electricity distributors in New York State.

2008 **Confidential client**

Contract design

Advised on design of structured contract for new renewable power plant, new electricity transmission lines and associated RFPs.

2008 **Commission for Energy Regulation**

Review of SOLR tariffs

Advise the Commission for Energy Regulation on the review of SOLR tariffs in the Republic of Ireland.

2008 **Comisión Nacional de Energía**

Market mechanisms for distributions to serve default customers

Advised on design and implementation of market mechanisms by which Spanish electric utilities buy energy to serve default customers.

2006–2009 **Hawaiian Electric Company**

Hedging options for fuel

Performed economic and accounting analysis of hedging options for low sulfur fuel oil, diesel and fuel oil on behalf of Hawaiian Electric Company.

2004–2010 **Commonwealth Edison and Ameren's Illinois utilities**

Competitive procurement for power supply

Advised Commonwealth Edison and Ameren's Illinois utilities on the design of a competitive procurement for short- and long-term power

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supply, including the contractual framework for energy purchases, 2004 to 2010.

2004–Present **New Jersey and Maryland distribution utilities**

Mark-to-market issues and credit policies

Advised several utilities in the Eastern Interconnection on mark-to-market issues and credit policies.

1999–2008 **New Jersey distribution utilities**

Contract design and implementation

Worked with credit representatives of New Jersey distribution utilities on contract design and implementation of the contract credit terms. Coordinated the utilities' responses to changes to the forms of letters of credit proposed by bidders; oversaw bidder credit qualification process; managed approval process for alternate guaranty instruments, and served as advisor to utilities when contract interpretation issues arose, 1999 to 2008.

1999–2008 **FirstEnergy Companies**

Competitive procurement for power supply

Advised the FirstEnergy Companies on the design of a competitive procurement for intermediate term power supply, including the contractual framework for energy purchases, 2004-2005.

2003 **Commission for Energy Regulation**

Hedging agreement and a power plant construction agreement

Advised the Commission for Energy Regulation in Ireland on the structure of a long-term hedging agreement and a power plant construction agreement; assisted with the development of the hedging contract and the tender documentation; performed bid evaluation.

2002 **Sierra Pacific Resources**

Risk management strategies

Advised a major west coast utility in the US on the development of its risk management policy and procedures; reviewed past trading and risk management strategies; and performed an assessment of its risk measurement and reporting techniques, including credit risk management policy.

2000 **Ministry of Energy, México**

Mexican IPP solicitation program

Advised on the development of the Mexican IPP solicitation program, including transaction structure (IPP v. BLT v. BOT), credit risk management, model contracts, and bid evaluation (the Comisión Federal

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de Electricidad has procured as much as 2000 MW per year of long-term power supply from IPPs).

2000 **Comisión Federal de Electricidad, Mexico**

Credit and collateral requirements for a power purchase agreement
Advised the Comisión Federal de Electricidad in Mexico on credit and collateral requirements for an-asset backed power purchase agreement with an IPP based in Mexico, including advice on the development of comparable credit and collateral requirements for an import transaction that was to be made on a firm basis with liquidated damages.

1998–2000 **Ministry of Energy, Mexico**

Restructuring and privatization of the Mexican electricity sector
Consulted to the Mexican Ministry of Energy on the restructuring and privatization of the Mexican electricity sector, the design of a competitive spot market, and the policy of IPP solicitations, electricity transmission pricing, upstream gas pricing and the development of a regulatory framework for the sector.

1998–1999 **Ministry of Energy, Mexico**

Assessing competition in restructured Mexican electric generation
Contributed to study assessing competition in restructured electric generation market in Mexico.

1999 **Swiss Re**

Novel insurance packages to hedge electric price and operations risk
Assisted Swiss Re in the development of the modeling for the creation of novel insurance packages to hedge electric price and operations risk, 1999.

1998 **Iberdrola S.A., Spain**

Seminars on the deregulated markets for gas and electricity in the US
Designed and conducted a series of three training courses for representatives of Iberdrola S.A. (Spain's principal private utility), which consisted of seminars on the deregulated markets for gas and electricity in the US, followed by a series of interviews with large utilities, IPPs, and energy marketers. Courses were designed to provide the European traders with an understanding of best practices employed by energy traders in the US, with respect to risk management (credit, market, and operational), 1998.

1998 **C.E.L.P.E, Brazil**

Risk management and energy trading
Assisted in training senior management of Iberdrola's Brazilian subsidiary C.E.L.P.E. in the area of risk management and energy trading.

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1998–2000 **Baltimore Gas & Electric Company**
Sector restructuring
Consultant to Baltimore Gas & Electric Company on sector restructuring.

1998–1999 **Baltimore Gas & Electric Company**
Valuation of electric power assets
Assisted in developing market value estimates of Baltimore Gas & Electric Company's generation fleet, including Calvert Cliffs Nuclear Power Plant.

1998 **Confidential Client**
Generation and fuel strategy
Participated in the development of a generation and fuel strategy for a large merchant generator and energy trader.

1996 **Iberdrola, S.A, Spain**
Restructuring of the electricity sector
Consultant to Iberdrola, S.A. on issues relating to the restructuring of the electricity sector in Spain.

1996 **Confidential client**
Investment strategy
Consultant to a major southeastern electric utility on investment strategy in the US including valuation of various targets.

1996 **Confidential client**
Competitive analysis of electric generation
Performed competitive analysis of electric generation market for utilities in eastern US.

1996 **New York State Electric and Gas Company**
Restructuring of the electricity market in New York State
Consultant to the New York State Electric and Gas Company on issues relating to the restructuring of the electricity market in New York State.

1995–1996 **New York Power Authority**
Sector restructuring
Consultant to senior management of the New York Power Authority on issues relating to the New York Competitive Opportunities Docket.

1995 **Southern California Edison Company**
Proposed restructuring of California's electric services industry
Consultant to Southern California Edison Company on issues relating to the California Public Utilities Commission's Proposed Policies Governing

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Restructuring California's Electric Services Industry and Reforming Regulation.

Publications and Presentations

2019 **Republic of Indonesia**
Presentations to Perusahaan Gas Negara, BHP Migas (regulator), and the Ministry of Energy and Mineral Resources of the Republic of Indonesia addressing the design and solicitation of natural gas distribution concessions. October, 2019.

2019 **Republic of Indonesia**
Presentations to Perusahaan Gas Negara and BHP Migas (regulator) addressing connection policies and market development strategies for greenfield natural gas distributors. October, 2019.

2019 **Florence School of Regulation**
Specialised Training on the Regulation of Gas Markets
Gas Sector Regulation: The US Experience
March 2019.

2019 **Electricity Journal**
Could Mexico's Capacity Market Design Lead to Gaming by Generators?
March 2019.

2018 **Perusahaan Gas Negara**
Specialized Training
Conducted specialized training course on the design and award of energy-sector concessions.
December 2018.

2018 **Center for Research in Regulated Industries**
Eastern Conference
Mexican Capacity Market Design and Market Power Potential
June 2018.

2018 **Florence School of Regulation**
Specialised Training on the Regulation of Gas Markets
Gas Sector Regulation: The US Experience
March 2018.

2017 **Electricity Journal**
Beyond net metering: A model for pricing services provided by and to distributed generation owners, such as rooftop solar.
April 2017.

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2017 **Law Seminars International Electric Utility Rate Case Conference**
Beyond Net Metering: Ratemaking Challenges from Distributed Generation.
Las Vegas, March 16 2017.

2017 **Public Utilities Fortnightly**
Interest Rates After the Election: What They Mean for Public Utility Returns.
January 2017.

2016 **Perusahaan Gas Negara, Jakarta, Indonesia**
Provided in-depth training on regulatory practice and tariff design for gas pipelines and distribution companies.
December 2016.

2016 **Electricity Journal**
Low interest rates and unprecedented stock market volatility: What they mean for your next rate case.
January-February 2016.

2016 **An Economic Analysis of the Acquisition of ConocoPhillips' Interest in the Beluga River Unit,** A Report Prepared for Chugach Electric Association, Inc. and Anchorage Municipal Light and Power, March 11, 2016.

2016 **Law Seminars International, 12th Annual National Conference on Current Issues in Electric Utility Ratemaking**
Policy Options to Address Cross Subsidies from Self Generation, March 14, 2016

2016 **International Arbitration Group of International Law Firm**
Applications of Economic Analysis in International Arbitration (with a focus on the Energy Sector)
New York, January 12, 2016

2015 **The Electricity Journal**
Low interest rates and unprecedented stock market volatility:
What they mean for your next rate case
December 2015

2015 **Utility Regulation Conference: Rate Case, ROE, and Reliability**
Brave New World for Return on Equity
Washington DC, December 10-11, 2015

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2015	**Law Seminars International, Energy in the Northeast** Energy Sector Developments and the Cost of Capital Boston, September 29, 2015
2015	**Law Seminars International, Rate Case Conference** A Brave New World for Return on Equity Las Vegas, March 5, 2014
2014	**Law Seminars International, Rate Case Conference** Current Challenges in Determining Appropriate Rates of Return for Public Utilities Las Vegas, February 28, 2014
2014	**National Energy Agency (China) and representatives of the State Grid** Regulatory Accounting and the FERC Uniform System of Accounts Beijing, January 16, 2014
2012	**Agencia Nacional de Petroleo, Gas Natural e Combustiveis (Brazil)** Natural Gas Pipeline Regulation in the United States (training course) Rio de Janiero, September 18-19, 2012
2012	**Center for Research in Regulated Industries Eastern Conference** Optimal Capital Structures for Regulated Public Utilities: When Does an Imputed Debt Ratio Make Sense for Ratemaking Purposes? Eastern Conference, Delaware May 18, 2012
2012	**Energy Policy Briefing Note** The Real Costs of Eliminating Unsecured Credit Lines and Requiring Cash Collateral in OTC Swaps Markets Co-author: Sharon Brown-Hruska, March 13, 2012
2012	**Law Seminars International, Electric Utility Rate Case Conference** Marginal Cost Pricing for Rate Design Las Vegas, February 2, 2012.
2012	**Center for Research in Regulated Industries** **Advanced Workshop in Regulation and Competition** Gas Pipeline Overearning Investigations Newark, New Jersey, January 13, 2012.
2011	**Working Group of Commercial Energy Firms** Cost-Benefit Analysis of the CFTC's Proposed Swap Dealer Definition December 20, 2011.

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2011	**Law Seminars International, Renewable Energy in the Pacific Northwest** Abundant Low-Cost Natural Gas? A Driver of Market Activity August 4, 2011.
2011	**Public Utilities Fortnightly** Zone of Reasonableness: Coping with Rising Profitability a Decade after Restructuring July 2011.
2011	**Law Seminars International, Electric Utility Rate Case Conference** Rate Design Issues Among Customer Classes Las Vegas, February 10, 2011.
2011	**Advanced Workshop in Regulation and Competition, Center for Research in Regulated Industries** Decoupling and the Cost of Equity Newark, New Jersey, January 14, 2011.
2010	**New York State Bar Association, Business Law Section Committee on Public Utility Law** Getting Renewables to Market: The Importance of Transmission Ratemaking Policy New York, July 24, 2010.
2009	**Law Seminars International Conference, Renewable Energy in New England** Getting Renewable Power to Market Boston, June 25, 2009.
2008	**Report for Baltimore Gas & Electric and Allegheny Power** Evaluation of Longer-Term Procurement Plans October 1, 2008.
2008	**Electricity Journal** The Continuing Rationale for Full and Timely Recovery of Fuel Price Levels in Fuel Adjustment Clauses July 2008.
2008	**Energy in the Southwest Conference** Natural Gas as a Fuel: Will There Be Enough? At What Prices? July 22, 2008.

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2007	**NERA Economic Consulting** The Line in the Sand: The Shifting Boundary Between Markets and Regulation in Network Industries. Coauthor.
2007	**Electric Utility and Natural Gas Interdependency** Managing Risk in Interdependent Gas and Power Markets Houston, March 6, 2007.
2004	**Electricity Journal** FERC Imposes New Constraints on Utility Procurement October 2004.
2003	**Northeast Gas Storage and Supply Strategies** Can Your Capital Structure Handle Today's Market, Credit and Liquidity Risks? Boston, June 17, 2003.
1996	**World Bank** Regulatory and institutional reforms in the Chinese power sector Contributor, 1996.
1993	**World Development** Political Economy, Convergence and Growth in Less Developed Countries Coauthor, 1993.

January 2019

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Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 4

Docket No. E-7, Sub 1214

Date of Request: December 10, 2019
Date of Response: December 20, 2019

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☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to Tech Customers Data Request No. 4-17, was provided to me by the following individual(s): Christine Perciaccante, CW-Professional, and was provided to Tech Customers under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 4
DEC Docket No. E-7, Sub 1214
Item No. 4-17
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Request:

17. Ms. McManeus writes: "Further, absent deferral the Company will experience a significant adverse earnings impact. The earnings degradation is expected to grow to over 100 basis points by 2022, the third year of the plan." (p. 39 lines 11-14) Please produce all analyses performed, memos or reports written, or presentations made by any employee, consultant or financial advisor of DEC pertaining to the determination that "absent deferral the Company will experience a significant adverse earnings impact" and pertaining to the finding that the "earnings degradation is expected to grow to over 100 basis points by 2022."

Response:

The analysis performed showing the earnings degradation can be found under PS 1.8 file name McManeus Grid Deferral Estimate.xlsx. There were no other memos, written reports, or presentations.

McManeus Grid Deferral Estimate.xls

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DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT

NC Retail ROEs Reported in E.S.-1 and Impacts of Potential Adjustments

Note: Adjustments are estimated at a high-level and may not be at the same level of precision as would be done in a rate case.

			Q1 2019				Q2 2019		
			Income for Common Equity (in $000)	Rate Base for Common Equity (in $000)	Return on Common Equity		Income for Common Equity (in $000)	Rate Base for Common Equity (in $000)	Return on Common Equity
		ES-1 Reference	*Sched 1, Line 11, Col f*	*Sched 1, Line 11, Col c*	*Income for C.E./Rate Base for C.E.*		*Sched 1, Line 11, Col f*	*Sched 1, Line 11, Col c*	*Income for C.E./Rate Base for C.E.*
1	1	**As Reported**	737,546	7,304,749	10.10%		777,069	7,516,016	10.34%
2	2	**Adjust Equity Ratio to Last Approved**	(606)	(16,818)	0.01%		(974)	(27,043)	0.02%
3	3	**Normalize Weather**	(56,047)		-0.77%		(47,756)		-0.64%
4	4	**Remove DSM/EE PPI Incentive**	(23,449)		-0.32%		(24,469)		-0.33%
5	5	**Adjust to End of Period Rate Base, including Interest Sync**	(13,307)	400,166	-0.64%		(8,459)	254,377	-0.42%
6	6	**Annualize Depreciation Expense, including adjustment to Reserve**	(41,746)	(28,321)	-0.51%		(37,160)	(25,210)	-0.45%
8	8	**Spread Severance Over 3 Years**	41,733		0.54%		41,755		0.54%
9	9	**Adjusted**	644,125	7,659,776	8.41%		700,006	7,718,141	9.07%
21		**Grid Improvement Plan Impacts without Deferral**							
22		2020 Revenue Requirements	(10,319)	132,246	-0.28%		(10,319)	132,246	-0.28%
23		2021 Revenue Requirements	(27,165)	335,682	-0.67%		(27,165)	335,682	-0.69%
24		2022 Revenue Requirements	(49,835)	584,120	-1.07%		(49,835)	584,120	-1.11%
87	**Grid Impacts -**		**2020**	**2021**	**2022**		**2020**	**2021**	**2022**
89		Cumulative Rate Base Impacts ($000)							
90		EPIS	257,012	663,075	1,170,019		257,012	663,075	1,170,019
91		Accum Depreciation	(2,693)	(17,534)	(46,712)		(2,693)	(17,534)	(46,712)
92		Reg Asset					-	-	-
93		ADIT on Reg Asset	-	-	-		-	-	-
94		Rate Base Impacts	254,318	645,541	1,123,307		254,318	645,541	1,123,307
95		Percent Equity	52%	52%	52%		52%	52%	52%
96		Equity Rate Base Impact	132,246	335,682	584,120		132,246	335,682	584,120
98		Annual Income Impacts ($000)							
99		Change in Debt Rate Base	122,073	309,860	539,187		122,073	309,860	539,187
100		Debt Rate	4.36%	4.36%	4.36%		4.36%	4.36%	4.36%
101		Interest Expense	5,322	13,510	23,509		5,322	13,510	23,509
103		Depreciation Expense	2,693	14,840	29,178		2,693	14,840	29,178
104		O&M	5,447	6,424	10,612		5,447	6,424	10,612
105		Property Tax	-	666	1,717		-	666	1,717
106		Total Expense	13,463	35,440	65,016		13,463	35,440	65,016
107		EBIT Impact	(13,463)	(35,440)	(65,016)		(13,463)	(35,440)	(65,016)
108		Tax Rate	23.35%	23.35%	23.35%		23.35%	23.35%	23.35%
109		After-Tax Impacts	(10,319)	(27,165)	(49,835)		(10,319)	(27,165)	(49,835)

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DUKE ENERGY CAROLINAS LLC
E7 Sub 1214
NORTH CAROLINA RETAIL GRID IMPROVEMENT
Capital Spend and Installation O&M Estimates
Dollars in Millions

Calculation of NC Retail Costs

Page 1 of 2

DEC Total Capital Spend

Strategic Category [1]	2020	2021	2022	5-year Total
Advanced DMS	$ 12	$ 12	$ 15	$ 40
AMI	$ -	$ -	$ -	-
Communication	$ 36	$ 48	$ 55	139
Enterprise Applications	$ 12	$ 10	$ 15	37
Hardening/Resiliency	$ 47	$ 26	$ 79	152
Self Optimizing Grid	$ 156	$ 290	$ 333	779
Targeted Underground	$ 14	$ 20	$ 45	79
Distributed Energy	$ 4	$ 1	$ 1	6
Transmission	$ 161	$ 174	$ 159	494
Other	$ -	$ -	$ -	-
				-
Total P/F Capital	**$ 443**	**$ 580**	**$ 703**	**$ 1,726**

DEC Total Installation O&M Spend

Strategic Category [1]	2020	2021	2022	5-year Total
Advanced DMS	$ 1	$ 1	$ 2	$ 4
AMI	-	-	-	-
Communication	2	3	4	9
Enterprise Applications	5	4	6	15
Hardening/Resiliency	2	1	3	5
Self Optimizing Grid	2	4	5	11
Targeted Underground	0	0	0	1
Distributed Energy	0	0	0	0
Transmission	2	2	2	5
Other	-	-	-	-
				-
Total O&M	**$ 14**	**$ 15**	**$ 21**	**$ 50**

DEC Total Capital Spend

SYSTEM	2020	2021	2022	3-year Total	NC Retail Allocation [2]
ADMS	12.5	11.8	15.4	39.6	74.79%
Communication	36.1	48.0	54.7	138.7	74.79%
Enterprise Appliaction	12.0	9.9	15.2	37.1	74.79%
Distributed Energy	4.0	0.5	1.0	5.5	74.79%
Distribution NC	158.5	278.1	360.2	796.9	Direct
Distribution SC	56.5	62.5	83.1	202.2	
Transmission	163.2	169.6	173.4	506.2	52.66%
TOTAL	442.8	580.4	703.0	1,726.2	

DEC Total Installation O&M Spend

SYSTEM	2020	2021	2022	3-year Total	NC Retail Allocation [2]
ADMS	1.3	1.2	1.6	4.1	74.79%
Communication	2.4	3.2	3.6	9.2	74.79%
Enterprise Appliaction	4.9	4.1	6.2	15.2	74.79%
Distributed Energy	0.3	0.1	0.1	0.5	74.79%
Distribution NC	2.8	4.0	6.1	12.9	Direct
Distribution SC	1.0	1.0	1.5	3.5	
Transmission	1.6	1.7	1.6	4.9	52.66%
TOTAL	14.4	15.3	20.7	50.3	

Page 2 of 2

DEC NC Retail Capital Spend

DEC NC Retail	2020	2021	2022	3-year Total
ADMS	9.3	8.8	11.5	29.6
Communication	27.0	35.9	40.9	103.8
Enterprise Appliaction	9.0	7.4	11.3	27.8
Distributed Energy	3.0	0.4	0.8	4.1
Distribution NC	158.5	278.1	360.2	796.9
Distribution SC				-
Transmission	86.0	89.3	91.3	266.6
TOTAL	292.8	419.9	516.0	1,228.7

DEC NC Retail Installation O&M Spend

DEC NC Retail	2020	2021	2022	3-year Total
ADMS	1.0	0.9	1.2	3.1
Communication	1.8	2.4	2.7	6.9
Enterprise Appliaction	3.7	3.0	4.6	11.4
Distributed Energy	0.2	0.0	0.1	0.3
Distribution NC	2.8	4.0	6.1	12.9
Distribution SC				-
Transmission	0.8	0.9	0.8	2.6
TOTAL	10.3	11.3	15.5	37.2

Plant in Service Assumptions [1]

Distribution	1 month
Transmission	6 months
Communication	3 months
Advanced DMS & Enterprise Application	Annually in December

[1] System numbers and Plant in Service assumptions from Witness Oliver
[2] Allocation factors from the Cost of service study.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 4

Docket No. E-7, Sub 1214

Date of Request: December 10, 2019
Date of Response: December 20, 2019

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The attached response to Tech Customers Data Request No. 4-5, was provided to me by the following individual(s): Christine Perciaccante, CW-Professional, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 4
DEC Docket No. E-7, Sub 1214
Item No. 4-5
Page 1 of 1

Request:

5. Please describe Ms. McManeus's understanding of the standard the North Carolina Utilities Commission has used to determine whether a proposed deferral is reasonable.

Response:

Please see Ms. McManeus's direct testimony in this matter, pages 39-41. Ms. McManeus believes the Commission looks at the nature and magnitude of the costs and whether the company will experience economic harm absent the deferral. As noted in the Company's petition in Docket No. E-7, Sub 1181, page 16, "the Commission has often applied a two-prong test to consider whether a requested cost deferral is justified: (1) whether the costs in question are unusual or extraordinary in nature, and (2) whether, absent deferral, the costs would have a material impact on the utility's financial condition." The company also looks to historical precedent from previous deferral requests and their outcomes.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-9, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-9
Page 1 of 1

Request:

9. Reference: Oliver, page 34, lines 1 to 13. Mr. Oliver lists three categories of the programs and projects DEC might use to address the Megatrends: "(1) compliance-driven programs that protect the grid, (2) rapid technology advancement programs that modernize the grid, and (3) various other projects and programs that work independently or together with other programs to optimize our customers' experience."
a. Does DEC's anticipated go-forward base T&D spend (e.g., not part of the Grid Improvement Plan) include projects that comply with obligations to protect the grid?
b. Does DEC's anticipated go-forward base T&D spend (e.g., not part of the Grid Improvement Plan) include projects that utilize "new" or "modern" T&D technologies (e.g., T&D technologies not available or not commonly utilized a decade ago)?
c. Does DEC's anticipated go-forward base T&D spend (e.g., not part of the Grid Improvement Plan) include projects and programs that optimize the customer's experience?
d. If the answer to a. is anything but an unqualified "no", please explain how DEC allocated expenses related to compliance into either base T&D spend or Grid Improvement Costs.
e. If the answer to b. is anything but an unqualified "no", please explain how DEC allocated expenses related to "new" or "modern" T&D technologies into either base T&D spend or Grid Improvement Costs.
f. If the answer to c. is anything but an unqualified "no", please explain how DEC allocated expenses related to projects and programs that optimize the customer's experience into either base T&D spend or Grid Improvement Costs.

Response:
a. Yes.
b. Yes.
c. Yes.

d. Please see page 34, line 2 through page 35, line 10 and Exhibits 1 and 4 of Witness Oliver's direct testimony in this matter.

e. Please see page 36, lines 14 through 18 and Exhibits 1 and 4 of Witness Oliver's direct testimony in this matter.

f. Please see page 39, line 4 through page 41, line 2 and Exhibits 1 and 4 of Witness Oliver's direct testimony in this matter.

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Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-1, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-1
Page 1 of 1

Request:

1. Reference: Oliver, page 12, lines 6-8. In Mr. Oliver's direct testimony, he includes "Expanded energy storage capabilities and infrastructure" as part of the Grid Improvement Plan.
a. Please confirm that DEC would seek to defer these expenses.
b. If answer to a. is anything but an unqualified "yes", please explain.
c. Mr. Oliver mentions that energy storage will "will help to power self-optimizing technologies" in the DEC grid. Does Mr. Oliver agree that energy storage might provide other benefits to DEC and its customers, e.g., providing ancillary services or shifting energy production?
d. Assuming the answer to c. is anything but an unqualified "yes", please explain.
e. Does DEC plan to allocate all energy storage CapEx expenses into Grid Modernization Plan expenses (and this seeking deferral)? Please explain.
f. If the answer to e. is no, please explain how DEC will allocate energy storage expenses.

Response:

a.DEC will determine the appropriate cost recovery mechanisms on a case by case basis.

b.DEC intends to recover costs associated with battery storage projects that have significant local reliability benefits in the same manner as other prudent investments needed to serve customers through general rate cases, or other rate recovery mechanisms as may be approved by the Commission.

c. Depending on the specific type of energy storage and the manner in which it is deployed, agreed.

d. Explanation provided in subpart c.

e. Please see responses to subparts a and b above.

f. Please see responses to subparts a and b above.

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Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-2, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-2
Page 1 of 1

Request:

2. Reference: Oliver, page 12, lines 12-14. Mr. Oliver includes "Voltage optimization and distribution of power to customers" as part of the Grid Improvement Plan, with the stated purpose to "improve reliability, increase system intelligence and support the two-way power flow needed to grow distributed resources."
a. Please explain what is meant by "distribution of power to customers" in this context.
b. Please confirm that DEC would seek to defer these expenses.
c. If answer to b. is anything but an unqualified "yes", please explain.
d. Does DEC include voltage optimization expense as well as part of its grid expenses that are not part of the Grid Improvement Plan?
e. If answer to d. is anything but an unqualified "no", please explain why some Voltage optimization expenses are in the Grid Improvement Plan and others are not.

Response:

a. Sensors and system intelligence to manage the more dynamic power flows of the modern grid, leveraging circuit re-configuration and 2-way power flow capability to manage distributed energy, renewable resources, electric vehicles, etc. This includes self-optimizing grid circuit ties, capacity and connectivity investments and IVVC related voltage management investments to enable two-way power flows and a modern voltage management capability that can re-route power to an alternate source during power interruption. This same ability to dynamically re-configure circuits to match circuit conditions supports grid management and operating capabilities to more efficiently integrate private rooftop solar and other distributed energy assets.

b. Confirmed.

c. Not applicable.

d. Yes.

e. Not applicable.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 26, 2019**
Date of Response: **January 6, 2020**

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The attached response to Tech Customers Data Request No. 6-18, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-18
Page 1 of 1

Request:

18. Reference: Duke Energy Carolinas Response to Tech Customers Data Request No. 6-2
Part e. of Data Request 6-2 states "If answer to d. is anything but an unqualified "no", please explain why some Voltage optimization expenses are in the Grid Improvement Plan and others are not." DEC's answer to part "d." was "Yes". Cleary, the response "Yes" is something other than an "unqualified 'no'". Thus, DEC should have provided the explanation requested in 6-2 e. Yet, DEC's response is "Not applicable".
a. Please explain why DEC's response to 6-2 e. was "not applicable", despite the fact that DEC answered "yes" to part 6-2 d.
b. Please provide the explanation requested in 6-2 e, assuming that DEC agrees the question is applicable.
c. If DEC continues to believe the question in 6-2 e. is not applicable, please explain why.

Response:

a. Data Request 6-2 does not read "If answer to d. is anything but an unqualified "no", please explain why some Voltage optimization expenses are in the Grid Improvement Plan and others are not." It reads "If answer to c. is anything but an unqualified "no", please explain why some Voltage optimization expenses are in the Grid Improvement Plan and others are not." The answer to 6-2c was "Not applicable" therefore the response to e was "Not applicable".
b. Assuming the question was asking about 6-2 d as noted above the response would be as follows: As part of grid management the Company must today maintain voltage levels per applicable standards. Equipment is required to be deployed and maintained on the current grid that performs this function. Today, much of this equipment operates independently and does not communicate to a central control system. The IVVC program that the Company describes in its GIP in Oliver Exhibit 10 pages 31 – 38 highlights the automation of line devices and performing voltage management on the distribution system in a conservation voltage reduction method not currently capable on the DEC distribution grid today.
c. See response to b above.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 26, 2019**
Date of Response: **January 6, 2020**

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The attached response to Tech Customers Data Request No. 6-19, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-19
Page 1 of 1

Request:

19. Reference: Duke Energy Carolinas Response to Tech Customers Data Request No. 6-3
Part d. of Data Request 6-3 states "If answer to c. is anything but an unqualified "no", please explain why some of these expenses are in the Grid Improvement Plan and others are not." DEC's answer to part "c." was "Yes". Cleary, the response "Yes" is something other than an "unqualified 'no'". Thus, DEC should have provided the explanation requested in 6-3 d. Yet, DEC's response is "Not applicable". (For clarity, "these expenses" in Data Request 6-3 part d. refers to "upgrading breakers, transformers, and other grid equipment, as well as … strategically underground[ing] the most vulnerable, outage-prone lines on the distribution system".)
a. Please explain why DEC's response to 6-3 d. was "not applicable", despite the fact that DEC answered "yes" to part 6-3 c.
b. Please provide the explanation requested in 6-3 d, assuming that DEC agrees the question is applicable.
c. If DEC continues to believe the question in 6-3 d. is not applicable, please explain why.

Response:

a. Response to 6-3 d was in error.
b. Yes, upgrading breakers, transformers, and other grid equipment and strategically undergrounding wires were part of the investments included in the test year in this case.
c. See response to b above.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 8

Docket No. E-7, Sub 1214

Date of Request: **January 21, 2020**
Date of Response: **January 31, 2020**

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The attached response to Tech Customers Data Request No. 8-2, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to Tech Customers under my supervision.

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Tech Customers
Data Request No. 8
DEC Docket No. E-7, Sub 1214
Item No. 8-2
Page 1 of 1

Request:

2. Please identify which specific capital investments proposed as part of the Grid Improvement Plan, have been made historically (2007- 2019) state under the following categories outlined:
a. Dis - Land & Land Rights -360
b. Dis - Structures & Improvements - 361
c. Dis - Station Equipment - 362
d. Dis - Energy Storage Equipment - 363
e. Dis - Poles, Towers & Fixtures - 364
f. Dis - Overhead Conductors & Devices - 365
g. Dis - Underground Conduit - 366
h. Dis - Underground Conductors & Devices - 367
i. Dis - Line Transformers - 368
j. Dis - Services - 369
k. Dis - Meters - 370
l. Dis - Installations on Customer Premises - 371
m. Dis - Leased Property on Customer Premises - 372
n. Dis - Street Lighting & Signal Systems - 373
o. Dis - Asset Retirement Costs - 374.

Response:
The only comparable parts of the Grid Improvement Plan that have historical base maintenance spending would be the Breaker Replacement Program and the Transformer Bank Replacement Program on the Transmission System and the Transformer Retrofit Program on the Distribution System.
The historical spend and impacted Distribution FERC accounts for the Transformer Retrofit Program is provided in Attachment "DEC Tech Cust DR 8-2 Transformer Retrofit." Note, actual data before 2009 from the asset records cannot be supported electronically at the program level due to a system conversion in 2009.

DEC Tech Cust DR
8-2 Transformer Retr

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 10

Docket No. E-7, Sub 1214

Date of Request: **February 4, 2020**
Date of Response: **February 13, 2020**

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The attached response to Tech Customers Data Request No. 10-2, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to Tech Customers under my supervision.

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Tech Customers
Data Request No. 10
DEC Docket No. E-7, Sub 1214
Item No. 10-2
Page 1 of 1

Request:

2. Reference Tech Customers DR 6-5(a). DEC was asked "Do you agree with this statement: Most if not all of these Megatrends have been trends in the electricity sector over the previous several years (by several, we mean for example at least 5 years, probably for 10 years, and perhaps as many as 20 years) and most if not all are likely to continue to be trends for the foreseeable future?" DEC responded, "Agree that the Megatrends are likely to continue to be trends for the foreseeable future."
a. The answer provided by DEC addresses the part of the question that looks towards the future but not the part of the question that considers the past. Thus, we ask this follow up question:
b. Do you agree with this statement: Most if not all of these Megatrends have been trends in the electricity sector over the previous several years (by several, we mean for example at least 5 years, probably for 10 years, and perhaps as many as 20 years).
c. If the answer to a. is anything but an unqualified "yes" please explain.

Response:

The complete response was inadvertently not included.
The full response that we intended is as follows:

Agree that many of the Megatrends have existed for five years or less. Disagree with "probably for 10 years" and "perhaps as many as 20 years." Agree that the Megatrends are likely to continue to be trends for the foreseeable future.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-5, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-5
Page 1 of 1

Request:

5. Reference: Oliver, page 28, line 8 to page 29, line 9. Mr. Oliver lists seven "Megatrends" that "are the factors that are driving the need for the Company to have a Grid Improvement Plan that goes beyond the work that the Company performs to maintain base-level operations."
a. Do you agree with this statement: Most if not all of these Megatrends have been trends in the electricity sector over the previous several years (by several, we mean for example at least 5 years, probably for 10 years, and perhaps as many as 20 years) and most if not all are likely to continue to be trends for the foreseeable future?
b. If the answer to a. is anything but an unqualified "yes" please explain.
c. In light of your answers to a. and b., are the expenses of Grid Improvement Plan unique where they require different regulatory treatment – i.e. deferral – in the present rate case specifically?
d. Please explain your answer to c.
e. With respect to the possibility that the megatrends will continue for the foreseeable future, is it reasonable for this Commission to expect that deferral for expenses related to the current Grid Improvement Plan and future programs of future grid improvement will be the "new normal" for DEC?
f. Please explain your answer to e.

Response:
a. Agree that the Megatrends are likely to continue to be trends for the foreseeable future.

b. Explained in subpart a above.

c. Yes.

d. Please see pages 52-55 of Witness Oliver's Direct Testimony in this matter.

e. DEC has sought deferral accounting treatment for the majority of the expenses set forth in the Grid
Improvement Plan proposed in this matter. DEC does not know whether it will seek other deferrals for costs related to grid improvement in the future.

f. DEC has not developed any future phases of the Grid Improvement Plan and thus cannot speculate as to how any such costs would be recovered.

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-15, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-15
Page 1 of 1

Request:

15. Reference: Oliver, page 54, line 11 to page 55, line 4. In this Q&A, Mr. Oliver discusses how, in the absence of an approval by this Commission to defer Grid Improvement Plan expenses, DEC would reassess the timing of and spending for the projects and programs that form the Grid Improvement Plan. Mr. Oliver concludes saying, "In such a situation, the Company would have to try and perform small pieces of the Grid Improvement Plan over a much longer period with its existing revenues, which will delay important benefits and potentially essential improvements for customers."
a. Has DEC estimated what Grid Improvement Plan programs and projects it would undertake – and the timing of these – in the absence of this Commission's approval of deferral of Grid Improvement Plan expenses? Please provide these estimates.
b. Please produce all analyses performed, memos or reports written, or presentations made by any employee, consultant or financial advisor of DEC pertaining to the Grid Improvement Plan projects and programs DEC would still implement (and the timing of those projects) in the absence of approval to defer Grid Improvement Plan projects.
c. Has DEC developed a cost-benefit analysis of the Grid Improvement Plan programs and projects it would undertake in the absence of this Commission's approval of deferral of Grid Improvement Plan expenses? Please provide this analysis if it exists.
d. Has DEC estimated the comparative rate impact on customers of a) a situation where the Commission's does not approve deferral of Grid Improvement Plan expenses vs. b) a situation where the Commission's approve the deferral of Grid Improvement Plan expenses matching DEC's request? Please provide this analysis if it exists.

Response:
a. No
b. Not applicable
c. No
d. No

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Feb 18 2020

Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-11, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

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Senior Counsel
Duke Energy Carolinas

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Feb 18 2020

Tech Customers
Data Request No. 6
DEC Docket No. E-7, Sub 1214
Item No. 6-11
Page 1 of 2

Request:

11. Reference: Oliver, page 36, line 10 to page 37, line 7. In this Q&A, Mr. Oliver discusses the rapid technology advancement category of work within the Grid Improvement Plan.
a. Did DEC conduct a cost-benefit analysis of all the programs and projects that fit into the rapid technology advancement category of work within the Grid Improvement Plan?
b. If the answer to a. is anything but an unqualified "yes", please explain,
c. Did DEC conduct a cost-benefit analysis for each rapid technology advancement program and project in the Grid Improvement Plan from the perspective of customers?
d. If the answer to c. is anything but an unqualified "yes", please explain,
e. Does DEC agree that, all things equal, that DEC's expenses related to the rapid technology advancement category of work within the Grid Improvement Plan will raise customer rates?
f. To the extent the answer to e. is "yes", please explain how DEC determined that the dollar value of the benefits to customers exceeded the costs in terms of higher rates, as related to the rapid technology advancement category of work within the Grid Improvement Plan.
g. How did DEC determine the chosen forecasted level of costs for the rapid technology advancement category of work within the Grid Improvement Plan (e.g., in general, how did DEC determine the programs to include and the amount to spend on the programs)?
h. Presumably the various programs and projects within the rapid-technology-advancement category in the Grid Improvement Plan have different ratios of benefits to costs from the customer perspective. Similarly, given a specific project or program, there may be diminishing returns as the spend of the program increases. To the extent not already covered in the answer to g., please describe how DEC arrived at the chosen forecasted level of costs for the rapid technology advancement category, specifically in light of the possibility of diminishing returns as spend increases and of certain projects having lower benefit-to-cost ratios than others.

Response:
a. No.

b. Please see page 37, lines 10 through 19 in Witness Oliver's direct testimony in this matter.

c. No.

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Feb 18 2020

d. Please see page 37, lines 10 through 19 in Witness Oliver's direct testimony in this matter.

e. Yes.

f. DEC did not. Please see page 37, lines 10 through 19 in Witness Oliver's direct testimony in this matter.

g. Please see page 36, line 10 through page 37, line 19; page 46, line 16 through page 50, line 19; and Exhibits 3 and 4 in Witness Oliver's direct testimony in this matter.

h. Not applicable. Please see subparts a-g above.

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Duke Energy Carolinas
Response to
Tech Customers Data Request
Data Request No. 6

Docket No. E-7, Sub 1214

Date of Request: **December 12, 2019**
Date of Response: **December 19, 2019**

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The attached response to Tech Customers Data Request No. 6-12, was provided to me by the following individual(s): Karen Ann Ralph, Senior Financial Analysist, Distribution Finance - Carolinas, and was provided to Tech Customers under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Tech Customers
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DEC Docket No. E-7, Sub 1214
Item No. 6-12
Page 1 of 2

Request:

12. Reference: Oliver, page 39, line 4 to page 41, line 2. In this Q&A, Mr. Oliver discusses the how DEC evaluated the projects and programs within the optimization category of the Grid Improvement Plan.
a. This Q&A discusses various cost-benefit analyses conducted by DEC related to optimization program expenses. Did DEC perform cost-benefit analysis of all the programs and projects that fit into the rapid advancement category of work within the Grid Improvement Plan?
b. If the answer to a. is anything but an unqualified "yes", please explain.
c. Did DEC conduct a cost-benefit analysis for each program and project in the Grid Improvement Plan related to optimization program expenses from the perspective of customers?
d. If the answer to c. is anything but an unqualified "yes", please explain,
e. Does DEC agree that, all things equal, that DEC's expenses related to the optimization category of work within the Grid Improvement Plan will raise customer rates?
f. To the extent the answer to e. is "yes", please explain how DEC determined that the dollar value of the benefits to customers exceeded the costs in terms of higher rates, as related to the optimization category of work within the Grid Improvement Plan.
g. How did DEC determine the chosen forecasted level of costs for the optimization category of work within the Grid Improvement Plan (e.g., in general, how did DEC determine the programs to include and the amount to spend on the programs)?
h. Presumably the various programs and projects within the optimization category in the Grid Improvement Plan have different ratios of benefits to costs from the customer perspective. Similarly, given a specific project or program, there may be diminishing returns as the spend of the program increases. To the extent not already covered in the answer to g., please describe how DEC arrived at the chosen forecasted level of costs for the optimization category, specifically in light of the possibility of diminishing returns as spend increases and of certain projects having lower benefit-to-cost ratios than others.

Response:
a. Please see the Company's response to Tech Customers Request 6-11.

b. Please see the Company's response to Tech Customers Request 6-11.

c. Yes.

d. Not applicable.

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e. Yes.

f. Please see Witness Oliver's Direct Testimony in this matter, Exhibit 7.

g. Please see page 38, line 1 through page 41, line 2; page 46, line 16 through page 50, line 19; and Exhibits 3 and 4 in Witness Oliver's direct testimony in this matter.

h. Please see DEC's responses to subparts a-g above.

I/A

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Feb 18 2020

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

Docket No. E-7, Sub 1214

Date of Request: **January 27, 2020**
Date of Response: **February 6, 2020**

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The attached response to Tech Customers Data Request No. 9-2, was provided to me by the following individual(s): Karen Ann Ralph, Lead Planning & Regulatory Support Specialist, and was provided to Tech Customers under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 9
DEC Docket No. E-7, Sub 1214
Item No. 9-2
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Request:

2. Reference: Oliver Testimony on Grid Improvement Plan
Mr. Oliver's testimony discusses DEC's Grid Improvement Plan. Separately, we understand DEC intends to make Integrated Systems and Operations Planning ("ISOP") "an integral part of the IRP in the future, complementing existing IRP tools and processes." DEC has stated it plans to incorporate ISOP in its 2022 IRP.
a. Does DEC expect that the incorporation of ISOP in its planning will affect what DEC decides are the appropriate distribution and transmission projects to invest in and will affect the level of investment into projects it identified? Please explain.
b. Might ISOP – once implemented – affect DEC's Grid Improvement Plan? Please explain.
c. Has DEC considered delaying Grid Improvement Plan expenses until it develops its ISOP approach? Please explain.
d. Please produce all analyses performed, memos or reports written, or presentations made by any employee, consultant or financial advisor of DEC pertaining to the consideration of whether the ISOP process will affect the Grid Improvement Plan.
e. Please produce all analyses performed, memos or reports written, or presentations made by any employee, consultant or financial advisor of DEC pertaining to the consideration of whether to delay the Grid Improvement Plan spend in anticipation of the coming ISOP?

Response:

a. No. The benefits of the investments proposed in this proceeding are not predicated on the integration of distribution, transmission and generation planning. ISOP planning tools and processes, when available, will leverage the foundational capabilities of the grid improvement plan to enable effective future investments across distribution, transmission, and generation.
b. No, not the Company's grid improvement plan proposed in this proceeding. See response to letter a above.
c. No, see also response to letter a above.
d. None
e. None

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

Docket No. E-7, Sub 1214

Date of Request: December 10, 2019
Date of Response: December 20, 2019

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The attached response to Tech Customers Data Request No. 2-1, was provided to me by the following individual(s): Jennifer Nelson, Director of ScottMadden, and was provided to Tech Customers under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 2
DEC Docket No. E-7, Sub 1214
Item No. 2-1
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Request:

1. On page 73 of Witness Hevert's direct testimony, he states that an ROE of 10.5% is supported by "the cost associated with issuing common stock and the current capital market environment, as well as DE Carolinas' risk profile relative to the proxy group analytical results with respect to (1) the risks associated with certain aspects of the Company's generation portfolio and (2) the Company's significant capital expenditure plan."
a. Please explain how the current capital market environment supports DEC having a return on equity of 10.5%.
b. Please explain how DEC's risk associated with certain aspects of its generation portfolio compare to risks associated with the proxy group's generation portfolio.
c. Please explain how DEC's significant capital expenditure plan compares to the expenditure plans of the proxy group.

Response:
a. Please see Mr. Hevert's Direct Testimony at pages 63-72.
b. Mr. Hevert has not performed the requested analysis.
c. Mr. Hevert has not performed the requested analysis.

/A

I/A

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Docket No. E-7, Sub 1214

Tech Customers
Strunk Exhibit KGS 17

"Cliffside Unit 5, Strategy Update"

Produced by DEC in Response to
Tech Customers Data Request No. 7-2

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Docket No. E-7, Sub 1214

Tech Customers
Strunk Exhibit KGS 18

"Allen Station Retirement Options"

Produced by DEC in Response to the North Carolina Public Staff's Data Request No. 65-14

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Docket No. E-7, Sub 1214

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Strunk Exhibit KGS 19

DEC RESPONSE TO TECH CUSTOMERS DATA REQUEST 7-2

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

Docket No. E-7, Sub 1214

Date of Request: **January 27, 2020**
Date of Response: **February 6, 2020**

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The attached response to Tech Customers Data Request No. 9-4, was provided to me by the following individual(s): David Charles Julius, Regulatory Strategy Manager, and was provided to Tech Customers under my supervision.

Camal O. Robinson
Senior Counsel
Duke Energy Carolinas

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Tech Customers
Data Request No. 9
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Item No. 9-4
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Request:

4. Reference: none
a. For each of DEC's coal-fired generation units, please indicate the capital expenditures that occurred between December 31, 2016 and December 31, 2018. Please break out the CAPEX by DEC unit. To be clear, we count 13 DEC coal units: Allen (1-5), Belews Creek (1-2), Cliffside (5-6), and Marshall (1-4).
b. For each of DEC's coal-fired generation units, please indicate what portion of the post-2016 CAPEX identified above was approved by the Commission as a post-test year addition to plant in Docket No. E-7, Sub 1146.

Response:

9-4a & b: Please see: "2019 DEC NC TC 9-4a&b.xls"

2019 DEC NC TC 9-4 a&b.xlsx

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2019 DEC NC
Docket No. E-7 Sub 1214
Tech Customers 9-4a

Coal Fired Generating Units	**Capital Expendiutres**
ALLEN STEAM PLT INSURABLE	$ 105,224,222.52
BELEWS CREEK PLT STOKES CO INSURABLE	$ 305,463,336.83
BELEWS CREEK STOKES CO NON INSURABLE	$ 527,211.00
BELEWS CREEK-ARO ASH	$ 197,325.10
BELEWS CREEK-ARO LANDFILL	$ 295,000.00
Cliffside 5 & 6 Common	$ 131,180,758.40
CLIFFSIDE UNIT 5 RUTHERFORD INSURABLE	$ 66,610,656.57
Cliffside Unit 6 - Cleveland County	$ 53,444,900.22
MARSHALL MULTIPLE PLANT EQUIP	$ 390,781.33
MARSHALL STEAM PLT INSURABLE	$ 280,717,500.40
MARSHALL STEAM PLT NON INSURABLE	$ (20,327.72)
Grand Total	$ 944,031,364.65

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2019 DEC NC
Docket No. E-7 Sub 1214
Tech Customers 9-4b

The below amount was included in the Docket No. E-7, 1146 case. These are additions to the Plant-in-service.

Coal Fired Generating Units	**Capital Expendiutres**
ALLEN STEAM PLANT NON INSURABLE	$ 606,975.71
ALLEN STEAM PLT INSURABLE	$ 32,278,789.69
BELEWS CREEK PLT STOKES CO INSURABLE	$ 106,936,868.46
BELEWS CREEK STOKES CO NON INSURABLE	$ -
BELEWS CREEK-ARO LANDFILL	$ 295,000.00
Cliffside 5 & 6 Common	$ 12,411,443.29
CLIFFSIDE UNIT 5 RUTHERFORD INSURABLE	$ 35,278,354.39
Cliffside Unit 6 - Cleveland County	$ 11,610,752.16
MARSHALL MULTIPLE PLANT EQUIP	$ 298,373.10
MARSHALL STEAM PLT INSURABLE	$ 41,708,476.92
MARSHALL STEAM PLT NON INSURABLE	$ (20,327.72)
Grand Total	$ 241,404,706.00

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Docket No. E-7, Sub 1214

Tech Customers
Strunk Exhibit KGS 21

DEC RESPONSE TO TECH CUSTOMERS DATA REQUEST 3-27

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Docket No. E-7, Sub 1214

Tech Customers
Strunk Exhibit KGS 22

Unprotected EDIT Flowback Survey

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Feb 18 2020

	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
1	Jan 31, 2020	TX	CenterPoint Energy Inc.	30-36 months	Elec	Settlement	Unprotected excess accumulated deferred federal income tax liabilities, referred to as UEDIT, in the amount of $105.4 million, plus carrying costs, would be refunded to ratepayers through a UEDIT rider for retail service and the wholesale transmission tariff over periods of between **30 months and 36 months**.[1]
2	Jan 27, 2020	VA	Roanoke Gas Co.	5 years	Gas	Order	In addition, the staff recommended that the company amortize protected excess accumulated deferred federal income tax using the Reverse South Georgia Method resulting in an amortization period of roughly 28 years and that Roanoke amortize unprotected excess accumulated deferred federal income tax balances over **five years**.[2]
3	Jan 16, 2020	NY	Consolidated Edison Co.	5 years	Elec/Gas	Order	The unprotected portion of the tax reform-related EDIT net regulatory liability totaling $784 million that is to be amortized over **five years**, or $157 million annually.[3]
4	Jan 16, 2020	ME	Central Maine Power Co.	Rate hike offset	Elec	Company proposal	While CMP supports a rate hike, the company proposed not to increase its distribution rates at this time. Instead, CMP proposed to **fully offset or "mitigate" its rate increase** by accelerating the amortization of the unprotected excess accumulated deferred income tax liability associated with federal tax reform.[4]
5	Jan 16, 2020	MO	Empire District Electric Co.	3 years	Elec	Company proposal	The company proposes to amortize the balance of unprotected excess ADIT over **three years** — a comparatively short period to "help minimize the rate increase impact on customers" — and protected excess ADIT using the average remaining life method.[5]
6	Jan 15, 2020	NY	New York State Electric & Gas Corp.	Elec 3 years; Gas 10 years	Elec/Gas	Company proposal	In the instant case, NYSEG proposes to return to electric ratepayers the January 2018 to September 2018 tax savings over a one-year period, protected EDIT in accordance with the average rate assumption method, or ARAM, protected pre-rate year-one liability of EDIT over a one-year period and unprotected EDIT over a **three-year period**. For its gas operations, NYSEG proposes to return to ratepayers protected EDIT in accordance with ARAM, the remaining balance of the protected pre-rate year-one liability of EDIT over a three-year period and unprotected EDIT over a **10-year period**.[6]

[1] "Rulings on CenterPoint, AEP Texas rate cases postponed due to illness," *S&P Global Market Intelligence*, 31 January 2020.

[2] "Roanoke Gas gets higher ROE than other Virginia utilities," *S&P Global Market Intelligence*, 27 January 2020.

[3] "NY PSC authorizes well-below-average ROE in 3-year rate plan for CECONY," *S&P Global Market Intelligence*, 16 January 2020.

[4] "PUC staff report calls for lower ROE for Central Maine Power due to inefficiency," *S&P Global Market Intelligence*, 16 January 2020.

[5] "Gap emerges between Empire District Electric, Mo. PSC staff on rate request," *S&P Global Market Intelligence*, 16 January 2020.

[6] "Hearings postponed again for further settlement talks in NYSEG, RG&E rate cases," *S&P Global Market Intelligence*, 15 January 2020.

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	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
7	Jan 15, 2020	NY	Rochester Gas and Electric Corp.	10 years	Elec/Gas	Company proposal	For both its electric and gas operations, RG&E proposes to return to ratepayers protected EDIT in accordance with ARAM, the remaining balance of the protected pre-rate year-one liability of EDIT over a three-year period and unprotected EDIT over a **10-year period**.[7]
8	Dec 27, 2019	NV	Sierra Pacific Power Co.	6 years	Elec	Settlement	In addition, SPP is to amortize excess accumulated deferred income tax, or ADIT, liabilities associated with federal tax reform over **six years**, as was proposed by the company.[8]
9	Dec 23, 2019	VA	Washington Gas Light Co.	10 years	Gas	Company proposal	The proposed revenue requirement also reflected the amortization of protected excess accumulated deferred federal income tax, or ADFIT, liabilities using the average rate assumption method, or ARAM, unprotected plant-related excess ADFIT liabilities using the ARAM and unprotected nonplant excess ADFIT liabilities over **10 years**.[9]
10	Dec 20, 2019	GA	Atlanta Gas Light Co.	Rate hike offset	Gas	Order	In addition to the $16 million in 2018 bill credits, AGL was expected use other portions of the benefits of the new tax law, including the excess accumulated deferred income taxes associated with unprotected assets, to **offset rate increases** it would have requested through its annual GRAM filing in 2018 and 2019 attributable to its capital expenditure plans.[10]
11	Dec 16, 2019	FERC	Oklahoma Gas & Electric	5 years	Elec/Gas	Order	In addition to the ROE reduction, the settlement provides that OG&E's excess ADIT liabilities associated with protected assets will be amortized over a period of time commensurate with the remaining useful lives of the underlying assets, while the company's unprotected excess ADIT liabilities will be amortized over **five years**.[11]
12	Dec 11, 2019	MS	Mississippi Power Co.	6 years	Elec	Company proposal	As part of the instant filing, MP is proposing to amortize an unspecified amount of excess accumulated deferred income tax, or ADIT, liabilities associated with federal tax reform over **six years**.[12]
13	Dec 5, 2019	IN	Northern Indiana Public Service Co.	11 years	Elec	Order	For the company's unprotected accumulated deferred income taxes balance of approximately **$137 million**, NIPSCO is to amortize **$12.2 million annually** beginning with the implementation of the second-step rate change.[13]

[7] *Ibid.*

[8] "Adopted settlement requires modest rate reduction, lower ROE for Sierra Pacific," *S&P Global Market Intelligence*, 27 December 2019.

[9] "Va. regulators deny rate increase for Washington Gas," *S&P Global Market Intelligence*, 23 December 2019.

[10] "Ga. regulators approve rate increase, new requirements for Atlanta Gas Light," *S&P Global Market Intelligence*, 20 December 2019.

[11] "Focus on FERC — Major Midcontinent ISO decision headlines parade of ROE cases," *S&P Global Market Intelligence*, 16 December 2019.

[12] "Mississippi Power files 1st rate case since 2001," *S&P Global Market Intelligence*, 11 December 2019.

[13] "New electric rates coming for Northern Indiana Public Service Co. customers," *S&P Global Market Intelligence*, 5 December 2019.

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	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
14	Dec 4, 2019	WA	Puget Sound Energy Inc.	4 years	Gas	Company proposal	PSE proposes amortizing the $36 million of electric and $2.9 million of gas unprotected EDIT, as of year-end 2017, over **four years** on a straight-line basis.[14]
15	Nov 22, 2019	WA	Avista Corp.	Accelerated depreciation offset	Elec	Settlement	The settlement specifies that tax benefits associated with federal tax reform would be utilized to **offset the increased costs associated with the acceleration of depreciation related to Colstrip**. The balance of unprotected excess deferred income taxes, or EDIT, would be **applied against the balance of net production plant in service**.[15]
16	Nov 19, 2019	MT	NorthWestern Corp.	5 years	Elec	Order	The approved settlement calls for protected federal excess deferred income taxes, or EDIT, to be amortized using the average rate assumption method, and unprotected nonplant EDIT would be amortized over a **five-year period**.[16]
17	Nov 18, 2019	NC	Piedmont Natural Gas Co.	5 years	Gas	Order	Under the order, PNG's protected federal excess deferred income taxes are to be amortized through base rates using the average rate assumption method, unprotected federal excess deferred income taxes would be returned over a five-year period, deferred revenues related to the federal income tax rate change would be returned to customers over a one-year period, and the state income tax rate change would be returned to customers over a **three-year period**.[17]
18	Nov 7, 2019	NY	Brooklyn Union Gas Co.	10-44 years	Gas	Company proposal	The rate requests sought by BUG and KGE reflected the amortization of protected excess accumulated deferred federal income tax, or EADFIT; liabilities using the average rate assumption method, or ARAM; the amortization of unprotected plant over the average remaining book life of the net book value of the assets; and the amortization of unprotected nonplant EADFIT over a period of **10 to 44 years for BUG** and 10 to 14 years for KGE.[18]
19	Nov 7, 2019	NY	KeySpan Gas East Corp.	10-14 years	Gas	Company proposal	The rate requests sought by BUG and KGE reflected the amortization of protected excess accumulated deferred federal income tax, or EADFIT; liabilities using the average rate assumption method, or ARAM; the amortization of unprotected plant over the average remaining book life of the net book value of the assets; and the amortization of unprotected nonplant EADFIT over a period of 10 to 44 years for BUG and **10 to 14 years for KGE**.[19]

[14] "Parties to Puget Sound Energy rate case recommend below-average ROE," *S&P Global Market Intelligence*, 4 December 2019.

[15] "Avista reaches settlement in Wash. electric and gas rate cases," *S&P Global Market Intelligence*, 22 November 2019.

[16] "Mont. utility commissioners approve electric rate hike for NorthWestern," *S&P Global Market Intelligence*, 19 November 2019.

[17] "Settlement of Piedmont's NC rate case to stagger return of tax benefits," *S&P Global Market Intelligence*, 18 November 2019.

[18] "Gas moratorium backlash could spell trouble for National Grid's gas rate cases," *S&P Global Market Intelligence*, 7 November 2019.

[19] *Ibid.*

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	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
20	Sep 5, 2019	WI	Northern States Power Co. - Wisconsin	Rate hike offset and bill credits	Elec	Order	The company will utilize the deferrals of the electric balance sheet component from 2018 and 2019 along with the remaining unprotected excess deferred income tax, or EDIT, balances to **offset certain regulatory assets and revenue requirement impacts**. The remaining unprotected EDIT balance will be returned to customers in the form of line-item **bill credits** through a credit surcharge in 2020.[20]
21	Aug 21, 2019	MO	Union Electric Co.	10 years	Elec	Company proposal	The company proposed to amortize "protected" plant-related excess ADIT using the average rate assumption method and proposed to use a **10-year amortization period** for "unprotected" nonplant excess ADIT.[21]
22	Aug 9, 2019	TX	Southwestern Public Service Co.	5 years	Elec	Order	Excess accumulated deferred federal income tax, or ADFITs, liabilities are being amortized in accordance with the average rate assumption method, or ARAM; unprotected, nonplant, excess ADFIT balances are being amortized over **five years**, and net operating loss-related balances are being amortized over a 44-year period, in accordance with the ARAM.[22]
23	Aug 5, 2019	TX	AEP Texas Inc.	5 years	Elec	Order	The revenue requirement reflected the prospective impact of tax reform as well as the amortization of protected EADFIT liabilities using the average rate assumption method and amortization of unprotected EADFIT liabilities over a **five-year period**.[23]
24	Jul 15, 2019	LA	Cleco Power LLC	6 years	Elec	Company proposal	Regarding excess accumulated deferred income tax, or ADIT, associated with federal tax reform, Cleco Power is proposing to amortize its unprotected excess ADIT balance over a **6-year period** beginning in 2021.[24]
25	Jul 9, 2019	VA	Columbia Gas of Virginia Inc.	5 years	Gas	Order	In addition, the base rate revenue requirement reflects amortization of related protected excess accumulated deferred federal income tax, or EADFIT, liabilities using the average rate assumption method, amortization of unprotected plant and non-plant EADFIT liabilities over **five years** and net operating loss carry-forward balances over 36.75 years.[25]

[20] "Commission interim order OKs settlement in Xcel Energy's Wisconsin rate case," *S&P Global Market Intelligence*, 5 September 2019.

[21] "Gas base rates in Mo. will effectively increase for Union Electric," *S&P Global Market Intelligence*, 21 August 2019.

[22] "Southwestern Public Service seeks rate increase for Hale Wind Farm," *S&P Global Market Intelligence*, 9 August 2019.

[23] "Commission staff recommends ring fencing, rate decrease for AEP Texas," *S&P Global Market Intelligence*, 5 August 2019.

[24] "Cleco Power files its 1st base rate case in 10 years," *S&P Global Market Intelligence*, 15 July 2019.

[25] "Va. decision for Columbia Gas recognizes infrastructure additions and tax reform," *S&P Global Market Intelligence*, 9 July 2019.

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	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
26	Jun 25, 2019	AZ	Southwest Gas Corp.	3 years	Gas	Company proposal	In addition, it is proposing to amortize the unprotected excess ADIT balance of $1 million over **three years**.[26]
27	Jun 5, 2019	NH	Public Service Co. of New Hampshire	5 years	Elec	Order	Unprotected EDFIT stemming from pension and other post-employment benefits is being amortized over 10 years, and all other unprotected EDFIT is being amortized over **five years**.[27]
28	May 14, 2019	NJ	Rockland Electric Co.	3 years	Elec	Commission requirement	The aggregate reduction includes a $2.9 million reduction that went into effect in April 1, 2018, for the decrease in the statutory tax rate to 21% from 35% and a $3.5 million reduction in July 2018 for the return to ratepayers over **three years** of the company's unprotected excess accumulated deferred federal tax liability.[28]
29	Apr 3, 2019	HI	Maui Electric Co. Ltd.	15 years	Elec	Settlement	Regarding tax issues, the settlement reflected amortization of an unprotected, plant-related excess accumulated deferred income tax, or ADIT, balance of $5.6 million over **15 years**.[29]
30	Mar 14, 2019	NJ	Atlantic City Electric Co.	10 years	Elec	Company proposal	With respect to unprotected excess accumulated deferred tax liabilities resulting from the tax changes, ACE proposes to amortize these balances over 10 years.[30]
31	Mar 14, 2019	NY	Orange and Rockland Utilities Inc.	15 years	Elec/Gas	Order	ORU is to amortize electric and gas protected excess deferred income tax balances resulting from tax reform over the remaining life of the underlying assets and the unprotected excess deferred income tax balances over **15 years** commencing Jan. 1, 2019.[31]
32	Mar 6, 2019	WV	Appalachian Power Co.	2 years	Elec	Order	The approved settlement provides for part of the companies' remaining balance of excess "unprotected" accumulated deferred federal income taxes due to federal tax reform to flow through a rider and offset part of the companies' revenue requirement over the next **two years**.[32]

[26] "Southwest Gas rate case in Arizona gets underway," *S&P Global Market Intelligence*, 25 June 2019.

[27] "Eversource files for permanent electric rate hike, grid plan in New Hampshire," *S&P Global Market Intelligence*, 5 June 2019.

[28] "Advanced metering, tree trimming drive Rockland Electric rate request," *S&P Global Market Intelligence*, 14 May 2019.

[29] "MECO authorized slightly below-average ROE; rate change to be determined," *S&P Global Market Intelligence*, 3 April 2019.

[30] "Atlantic City Electric gets substantially reduced rate hike after settlement," *S&P Global Market Intelligence*, 14 March 2019.

[31] "NY regulators adopt 3-year rate plan for Orange and Rockland Utilities," *S&P Global Market Intelligence*, 14 March 2019.

[32] "Rate hike for AEP's W.Va. customers to be partially mitigated by tax credits," *S&P Global Market Intelligence*, 6 March 2019.

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	Article Date	State	Company	Flowback	Type	Policy Status	Article Quotation
33	Mar 6, 2019	WV	Wheeling Power Co.	2 years	Elec	Order	The approved settlement provides for part of the companies' remaining balance of excess "unprotected" accumulated deferred federal income taxes due to federal tax reform to flow through a rider and offset part of the companies' revenue requirement over the next **two years**.[33]
34	Feb 5, 2019	KS	ONE Gas Inc.	5 years	Gas	Order	In addition, for purposes of amortizing the company's excess accumulated deferred income tax balance, the average rate assumption method is to be used for "protected" assets, and a **five-year amortization period** is to be used for "unprotected" assets.[34]

[33] *Ibid.*

[34] "Kansas Gas Service poised to implement rate hike following commission order," *S&P Global Market Intelligence*, 5 February 2019.

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
ALLETE, Inc.	High Price ($)	84.710	84.170	77.390	63.350	59.270	64.900
	Low Price ($)	79.400	67.990	50.010	53.290	48.220	51.600
	Avg. Price ($)	82.055	76.080	63.700	58.320	53.745	58.250
	Dividend ($)	0.588	0.618	0.618	0.618	0.618	0.618
	Mo. Avg. Div.	2.86%	3.25%	3.88%	4.24%	4.60%	4.24%
	6 mos. Avg.	3.84%					
Alliant Energy Corp.	High Price ($)	59.740	60.280	58.150	54.450	49.720	52.470
	Low Price ($)	53.320	51.250	37.660	43.610	44.360	46.150
	Avg. Price ($)	56.530	55.765	47.905	49.030	47.040	49.310
	Dividend ($)	0.380	0.380	0.380	0.380	0.380	0.380
	Mo. Avg. Div.	2.69%	2.73%	3.17%	3.10%	3.23%	3.08%
	6 mos. Avg.	3.00%					
Ameren Corp.	High Price ($)	82.410	87.330	87.660	81.250	75.270	77.420
	Low Price ($)	75.540	77.190	58.740	65.900	66.330	67.140
	Avg. Price ($)	78.975	82.260	73.200	73.575	70.800	72.280
	Dividend ($)	0.495	0.495	0.495	0.495	0.495	0.495
	Mo. Avg. Div.	2.51%	2.41%	2.70%	2.69%	2.80%	2.74%
	6 mos. Avg.	2.64%					
American Electric Power Co.	High Price ($)	104.430	104.970	100.650	88.290	85.850	88.120
	Low Price ($)	92.940	86.420	65.140	71.200	76.230	77.150
	Avg. Price ($)	98.685	95.695	82.895	79.745	81.040	82.635
	Dividend ($)	0.700	0.700	0.700	0.700	0.700	0.700
	Mo. Avg. Div.	2.84%	2.93%	3.38%	3.51%	3.46%	3.39%
	6 mos. Avg.	3.25%					
Avista Corp.	High Price ($)	50.910	52.430	53.000	45.760	42.530	40.840
	Low Price ($)	46.180	45.940	32.090	38.780	34.520	33.340
	Avg. Price ($)	48.545	49.185	42.545	42.270	38.525	37.090
	Dividend ($)	0.388	0.405	0.405	0.405	0.405	0.405
	Mo. Avg. Div.	3.20%	3.29%	3.81%	3.83%	4.21%	4.37%
	6 mos. Avg.	3.78%					
Avangrid, Inc.	High Price ($)	53.935	57.240	53.995	46.830	44.610	47.080
	Low Price ($)	50.210	47.240	35.620	39.720	38.780	40.650
	Avg. Price ($)	52.073	52.240	44.807	43.275	41.695	43.865
	Dividend ($)	0.440	0.440	0.440	0.440	0.440	0.440
	Mo. Avg. Div.	3.38%	3.37%	3.93%	4.07%	4.22%	4.01%
	6 mos. Avg.	3.83%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
CMS Energy Corp.	High Price ($)	68.980	69.170	68.990	64.080	58.960	61.190
	Low Price ($)	61.570	59.120	46.030	53.960	52.350	55.800
	Avg. Price ($)	65.275	64.145	57.510	59.020	55.655	58.495
	Dividend ($)	0.383	0.408	0.408	0.408	0.408	0.408
	Mo. Avg. Div.	2.34%	2.54%	2.83%	2.76%	2.93%	2.79%
	6 mos. Avg.	2.70%					
DTE Energy Co.	High Price ($)	134.720	135.670	119.490	113.300	108.730	117.910
	Low Price ($)	127.620	110.200	71.210	85.530	92.390	102.190
	Avg. Price ($)	131.170	122.935	95.350	99.415	100.560	110.050
	Dividend ($)	1.013	1.013	1.013	1.013	1.013	1.013
	Mo. Avg. Div.	3.09%	3.29%	4.25%	4.07%	4.03%	3.68%
	6 mos. Avg.	3.74%					
Evergy, Inc.	High Price ($)	72.620	76.570	73.160	64.700	62.680	65.400
	Low Price ($)	62.930	63.180	42.010	50.640	54.000	57.600
	Avg. Price ($)	67.775	69.875	57.585	57.670	58.340	61.500
	Dividend ($)	0.505	0.505	0.505	0.505	0.505	0.505
	Mo. Avg. Div.	2.98%	2.89%	3.51%	3.50%	3.46%	3.28%
	6 mos. Avg.	3.27%					
Hawaiian Electric Ind.	High Price ($)	49.630	50.550	55.150	46.660	39.920	40.760
	Low Price ($)	45.040	42.030	33.510	38.790	34.930	34.790
	Avg. Price ($)	47.335	46.290	44.330	42.725	37.425	37.775
	Dividend ($)	0.320	0.330	0.330	0.330	0.330	0.330
	Mo. Avg. Div.	2.70%	2.85%	2.98%	3.09%	3.53%	3.49%
	6 mos. Avg.	3.11%					
NextEra Energy, Inc.	High Price ($)	270.660	283.350	282.570	250.870	256.510	262.260
	Low Price ($)	237.950	243.080	174.800	213.040	222.620	233.760
	Avg. Price ($)	254.305	263.215	228.685	231.955	239.565	248.010
	Dividend ($)	1.250	1.400	1.400	1.400	1.400	1.400
	Mo. Avg. Div.	1.97%	2.13%	2.45%	2.41%	2.34%	2.26%
	6 mos. Avg.	2.26%					
Northwestern Corp.	High Price ($)	77.340	80.520	78.080	65.380	61.420	64.170
	Low Price ($)	69.690	69.490	45.060	52.470	52.100	51.000
	Avg. Price ($)	73.515	75.005	61.570	58.925	56.760	57.585
	Dividend ($)	0.575	0.575	0.600	0.600	0.600	0.600
	Mo. Avg. Div.	3.13%	3.07%	3.90%	4.07%	4.23%	4.17%
	6 mos. Avg.	3.76%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
OGE Energy Corp.	High Price ($)	46.330	46.430	40.320	33.770	32.940	34.910
	Low Price ($)	43.220	37.160	23.010	26.370	27.960	29.220
	Avg. Price ($)	44.775	41.795	31.665	30.070	30.450	32.065
	Dividend ($)	0.388	0.388	0.388	0.388	0.388	0.388
	Mo. Avg. Div.	3.46%	3.71%	4.89%	5.15%	5.09%	4.83%
	6 mos. Avg.	4.52%					
Otter Tail Corp.	High Price ($)	54.300	56.900	51.990	48.220	45.080	44.610
	Low Price ($)	50.830	47.560	30.950	41.070	36.700	36.800
	Avg. Price ($)	52.565	52.230	41.470	44.645	40.890	40.705
	Dividend ($)	0.350	0.370	0.370	0.370	0.370	0.370
	Mo. Avg. Div.	2.66%	2.83%	3.57%	3.32%	3.62%	3.64%
	6 mos. Avg.	3.27%					
Pinnacle West Capital Corp.	High Price ($)	98.810	105.510	100.730	84.690	78.670	82.290
	Low Price ($)	88.100	88.600	60.050	67.290	69.560	69.960
	Avg. Price ($)	93.455	97.055	80.390	75.990	74.115	76.125
	Dividend ($)	0.783	0.783	0.783	0.783	0.783	0.783
	Mo. Avg. Div.	3.35%	3.22%	3.89%	4.12%	4.22%	4.11%
	6 mos. Avg.	3.82%					
PNM Resources, Inc.	High Price ($)	55.240	56.140	52.240	46.820	41.380	43.500
	Low Price ($)	48.520	45.470	27.080	35.390	34.240	36.930
	Avg. Price ($)	51.880	50.805	39.660	41.105	37.810	40.215
	Dividend ($)	0.308	0.308	0.308	0.308	0.308	0.308
	Mo. Avg. Div.	2.37%	2.42%	3.10%	2.99%	3.25%	3.06%
	6 mos. Avg.	2.87%					
Portland General Electric Co.	High Price ($)	61.710	63.080	59.810	53.420	47.500	48.730
	Low Price ($)	54.550	53.270	37.830	44.580	39.510	40.200
	Avg. Price ($)	58.130	58.175	48.820	49.000	43.505	44.465
	Dividend ($)	0.385	0.385	0.385	0.385	0.385	0.385
	Mo. Avg. Div.	2.65%	2.65%	3.15%	3.14%	3.54%	3.46%
	6 mos. Avg.	3.10%					
Southern Company	High Price ($)	71.100	70.780	68.560	61.860	57.710	60.470
	Low Price ($)	62.240	59.070	41.960	49.260	51.990	50.400
	Avg. Price ($)	66.670	64.925	55.260	55.560	54.850	55.435
	Dividend ($)	0.620	0.620	0.620	0.620	0.640	0.640
	Mo. Avg. Div.	3.72%	3.82%	4.49%	4.46%	4.67%	4.62%
	6 mos. Avg.	4.30%					

PROXY GROUP
AVERAGE PRICE, DIVIDEND AND DIVIDEND YIELD

		Jan-20	Feb-20	Mar-20	Apr-20	May-20	Jun-20
WEC Energy Group, Inc.	High Price ($)	101.370	103.280	109.530	101.000	91.960	95.820
	Low Price ($)	90.340	90.160	68.010	80.560	81.490	83.840
	Avg. Price ($)	95.855	96.720	88.770	90.780	86.725	89.830
	Dividend ($)	0.590	0.633	0.633	0.633	0.633	0.633
	Mo. Avg. Div.	2.46%	2.62%	2.85%	2.79%	2.92%	2.82%
	6 mos. Avg.	2.74%					
Xcel Energy	High Price ($)	69.620	72.140	70.680	67.440	65.310	67.540
	Low Price ($)	61.970	61.250	46.580	56.960	56.070	61.580
	Avg. Price ($)	65.795	66.695	58.630	62.200	60.690	64.560
	Dividend ($)	0.405	0.405	0.430	0.430	0.430	0.430
	Mo. Avg. Div.	2.46%	2.43%	2.93%	2.77%	2.83%	2.66%
	6 mos. Avg.	2.68%					
Monthly Avg. Dividend Yield		2.84%	2.92%	3.48%	3.50%	3.66%	3.54%
6-month Avg. Dividend Yield		3.32%					

Source: Yahoo! Finance

PROXY GROUP
DCF Growth Rate Analysis

Company	(1) Value Line DPS	(2) Value Line EPS	(3) Zacks	(4) Yahoo! Finance
ALLETE, Inc.	4.50%	5.50%	7.00%	7.00%
Alliant Energy Corporation	5.50%	6.50%	5.50%	5.30%
Ameren Corp.	5.00%	6.00%	6.80%	5.90%
American Electric Power Co.	5.50%	5.00%	5.80%	5.88%
Avangrid, Inc.	2.50%	6.00%	5.50%	6.40%
Avista Corp.	4.00%	1.00%	5.20%	6.00%
CMS Energy Corporation	7.00%	7.50%	6.90%	7.16%
DTE Energy Company	6.50%	5.00%	5.50%	5.84%
Evergy, Inc.	5.50%	3.00%	5.00%	3.90%
Hawaiian Electric	4.00%	3.50%	1.70%	3.30%
NextEra Energy, Inc.	10.50%	10.00%	7.80%	8.07%
Northwestern Corporation	4.00%	2.50%	3.40%	3.70%
OGE Energy Corp.	6.00%	3.00%	3.70%	2.40%
Otter Tail Corporation	5.00%	3.50%	9.00%	9.00%
Pinnacle West Capital Corp.	5.50%	4.50%	5.20%	4.48%
PNM Resources, Inc.	5.50%	6.00%	6.10%	5.65%
Portland General Electric Company	6.00%	4.00%	5.30%	4.15%
Southern Company	3.00%	3.00%	4.00%	4.52%
WEC Energy Group	6.50%	6.00%	5.90%	5.90%
Xcel Energy Inc.	6.00%	6.00%	5.90%	6.00%
Average	5.40%	4.88%	5.56%	5.53%
Median	5.50%	5.00%	5.50%	5.86%

Sources: **Value Line Investment Survey, April 24, May 15, and June 12, 2020**
Yahoo! Finance and Zacks growth rates retrieved June 23, 2020
Yahoo! Finance growth rates used for Zacks growth rates for ALLETE, Otter Tail

PROXY GROUP
DCF RETURN ON EQUITY

	(1) Value Line Dividend Gr.	(2) Value Line Earnings Gr.	(3) Zack's Earning Gr.	(4) Yahoo! Earning Gr.	(5) Average of All Gr. Rates
Method 1:					
Dividend Yield	3.32%	3.32%	3.32%	3.32%	3.32%
Average Growth Rate	5.40%	4.88%	5.56%	5.53%	5.34%
Expected Div. Yield	3.41%	3.41%	3.42%	3.42%	3.41%
DCF Return on Equity	***8.81%***	***8.29%***	***8.98%***	***8.95%***	***8.75%***
Method 2:					
Dividend Yield	3.32%	3.32%	3.32%	3.32%	3.32%
Median Growth Rate	5.50%	5.00%	5.50%	5.86%	5.47%
Expected Div. Yield	3.42%	3.41%	3.42%	3.42%	3.41%
DCF Return on Equity	***8.92%***	***8.41%***	***8.92%***	***9.28%***	***8.88%***

PROXY GROUP
Capital Asset Pricing Model Analysis

30-Year Treasury Bond, Value Line Beta

Line No.		Value Line
1	Market Required Return Estimate	11.90%
2	Risk-free Rate of Return, 30-Year Treasury Bond	
3	Average of Last Six Months	1.63%
4	Risk Premium	
5	(Line 1 minus Line 3)	10.26%
6	Comparison Group Beta	0.74
7	Comparison Group Beta * Risk Premium	
8	(Line 5 * Line 6)	7.62%
9	CAPM Return on Equity	
10	(Line 3 plus Line 8)	9.25%

Duff and Phelps Normalized Risk-free Rate

1	Market Required Return Estimate	11.90%
2	Duff and Phelps Normalized Risk-free Rate	3.00%
3	Risk Premium	
4	(Line 1 minus Line 2)	8.90%
5	Proxy Group Beta	0.74
6	Proxy Group Beta * Risk Premium	
7	(Line 4 * Line 5)	6.61%
8	CAPM Return on Equity	
9	(Line 2 plus Line 7)	9.61%

PROXY GROUP
Capital Asset Pricing Model Analysis

Supporting Data for CAPM Analyses

30 Year Treasury Bond Data

	Avg. Yield
January-20	2.22%
February-20	1.97%
March-20	1.46%
April-20	1.27%
May-20	1.38%
June-20	1.49%
6 month average	1.63%

Source: www.federalreserve.gov

Value Line Market Return Data:

Forecasted Data:	
Value Line Median Growth Rates:	
Earnings	9.00%
Book Value	6.50%
Average	7.75%
Average Dividend Yield	1.24%
Estimated Market Return	9.04%
Value Line Projected 3-5 Yr.	
Median Annual Total Return	14.00%
Average Annual Total Return	15.51%
Average	14.76%
Average of Projected Mkt. Returns	11.90%

Source: Value Line Investment Analyzer, June 24, 2020

Comparison Group Betas:	Value Line
ALLETE, Inc.	0.85
Alliant Energy Corporation	0.80
Ameren Corp.	0.80
American Electric Power Co.	0.75
Avangrid, Inc.	0.80
Avista Corp.	0.60
CMS Energy Corporation	0.80
DTE Energy Company	0.90
Evergy, Inc.	1.05
Hawaiian Electric	0.55
NextEra Energy, Inc.	0.85
Northwestern Corporation	0.55
OGE Energy Corp.	1.05
Otter Tail Corporation	0.85
Pinnacle West Capital Corp.	0.45
PNM Resources, Inc.	0.50
Portland General Electric Company	0.55
Southern Company	0.90
WEC Energy Group	0.80
Xcel Energy Inc.	0.45
Average	0.74

PROXY GROUP
Capital Asset Pricing Model Analysis
Historic Market Premium

	Arithmetic Mean	Adjusted Arithmetic Mean
CAPM with Current 30-Year Treasury Yield		
Long-Term Annual Return on Stocks	12.10%	
Long-Term Annual Income Return on Long-Term Treas. Bonds	4.90%	
Historical Market Risk Premium	7.20%	6.14%
Proxy Group Beta, Value Line	0.74	0.74
Beta * Market Premium	5.35%	4.56%
Current 30-Year Treasury Bond Yield	1.63%	1.63%
CAPM Cost of Equity, Value Line Beta	**6.98%**	**6.19%**
CAPM with D&P Normalized Risk-Free Rate		
Historical Market Risk Premium	7.20%	6.14%
Proxy Group Beta, Value Line	0.74	0.74
Beta * Market Premium	5.35%	4.56%
D&P Normalized Risk-Free Rate	3.00%	3.00%
CAPM Cost of Equity, Normalized Risk-Free Rate	**8.35%**	**7.56%**

Source: Duff and Phelps Cost of Capital Navigator
2020 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 2, Exhibit 2.3,
2019 Cost of Capital: Annual U.S. Guidance and Examples, Chapter 3, pages 45-47

Public Staff
Metz Exhibit 1

SOWELL GRAY ROBINSON
Litigation + Business

FRANK R. ELLERBE, III
DIRECT 803 227.1112 DIRECT FAX 803 744.1556
fellerbe@sowellgray.com

February 21, 2017

VIA ELECTRONIC FILING

Ms. Jocelyn Boyd
Chief Clerk & Administrator
Public Service Commission of South Carolina
Synergy Business Park, Saluda Building
101 Executive Center Drive, Suite 100
Columbia, SC 29210

Re: Application for a CPCN to Provide Steam Service and for Contract Approval on behalf of Duke Energy Carolinas, LLC

Dear Ms. Boyd:

Enclosed for filing please find Duke Energy Carolinas, LLC's Application for a Certificate of Public Convenience and Necessity to Provide Steam Service and approval of a contract to provide steam service. By copy of this letter we are providing a copy of same to the Office of Regulatory Staff. Should you have any questions, please contact me.

Yours truly,

Frank R. Ellerbe, III

FRE:tch

Enclosure

cc w/enc: Shannon B. Hudson, Deputy Director Legal Services (via email)
Heather Shirley Smith, Deputy General Counsel (via email)
Rebecca J. Dulin, Senior Counsel (via email)

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

In the matter of: Duke Energy Carolinas, LLC's Application for a Certificate of Public Convenience and Necessity for the Provision of Steam (Heat) Service and for Approval of a Contract with Clemson University	)	**DUKE ENERGY CAROLINAS, LLC'S APPLICATION FOR A CPCN TO PROVIDE STEAM SERVICE AND FOR CONTRACT APPROVAL**

Duke Energy Carolinas, LLC ("DEC" or "Company") hereby applies to the Public Service Commission of South Carolina ("Commission"), pursuant to S.C. Code Ann. § 58-5-10 (Supp. 2014) *et seq.* and 10 S.C. Code Ann. Reg. 103-823 (2014), and other applicable rules and regulations of the Commission for a Certificate of Public Convenience and Necessity to sell steam (heat) service. DEC proposes to construct a Combined Heat and Power Generating Facility ("CHP Facility") at Clemson University ("Clemson") to provide electric service to its system customers and thermal energy supply to Clemson. In addition, pursuant to S.C. Code Ann. 58-27-830 and 10 S.C. Code Ann. Reg. 103-303, DEC also seeks approval of the Steam Supply and Purchase Agreement ("Agreement") to provide steam service, and electric service in emergency islanding scenarios, to Clemson. The CHP Facility will be used to serve both Clemson and DEC's other wholesale and retail customers as described in detail below.

In support of this Application, DEC would show the following:

1. The correct name and address of DEC are

   Duke Energy Carolinas, LLC
   Post Office Box 1321
   Charlotte, NC 28201

2. The name and addresses of the attorneys of DEC who are authorized to receive notices and communications with respect to this application are:

Heather Shirley Smith
Deputy General Counsel
Duke Energy Business Services, LLC
40 West Broad St, Suite 690
Greenville, SC 29601
Telephone 864.370.5045
heather.smith@duke-energy.com

and

Frank R. Ellerbe, Esquire
Sowell, Gray, Robinson, Stepp and Laffitte, LLC
P.O. Box 11449
Columbia, South Carolina 29211
Telephone: (803) 227-1112
fellerbe@sowellgray.com

3. DEC is engaged in the generation, transmission, distribution, and sale of electric energy at retail in South Carolina and North Carolina. DEC also sells electricity at wholesale to municipal, cooperative, and investor-owned electric utilities and its wholesale sales are subject to the jurisdiction of the FERC.

4. Clemson University is an institution of higher learning of the State of South Carolina and is governed by its Board of Trustees pursuant to the provisions of S.C. Code Ann. §§59-119-10 *et seq*.

5. Combined heat and power is an efficient and clean approach to generating power and thermal energy from a single fuel source. DEC's CHP Facility will recover otherwise-wasted thermal energy to produce thermal energy for use by Clemson. By using waste heat recovery technology, CHP systems typically achieve total system efficiencies of 60 to 80% for producing

electricity and thermal energy. Because CHP is more efficient, less fuel is required to produce a given energy output than with separate heat and power. Higher efficiency translates into lower operating costs, reduced emissions of all pollutants, increased reliability and power quality, reduced grid congestion, and avoided distribution losses.

6. The CHP Facility will be a natural gas cogeneration power plant with a capacity of 16 megawatts. It will be located on a site leased from Clemson in Pickens County. DEC expects the CHP Facility to commence operations by April of 2019. The CHP Facility will consist of one natural gas turbine, a heat recovery steam generator, gas compressor, and chilled water system. It will be interconnected to the Company's transmission system and the power generated by the CHP Facility will be exported to the DEC system to serve its customers. All thermal energy recovered from the process of power generation at the CHP Facility will be sold to Clemson to meet its thermal energy requirements. Further, pursuant to the Agreement, in the event of a major grid disturbance, the CHP Facility will be available to provide 16 MW of back-up, emergency power generation to the University.

7. The CHP Facility is a cost-effective approach to add new electric generating capacity to DEC's portfolio to benefit all of its customers, including Clemson. The Company's 2016 Integrated Resource Plan, filed in Docket No. 2016-9-E, includes specific investments in CHP capacity to DEC's generating portfolio. DEC estimates that the cost to construct the CHP Facility will be $50.8 MM.

8. The Agreement, attached hereto as Exhibit A to the Application, sets forth the terms and conditions of the steam supply and electrical islanding capabilities, from the Company to Clemson for the duration of the contract term, which is thirty-five (35) years. Pursuant to the Agreement, and the terms of the Company's existing effective electric service regulations, in

addition to its payments for the purchase of steam from the Company, Clemson will also pay an Extra Facilities Charge related to the availability of the CHP Facility to island and power the campus during a major grid outage.

9. DEC seeks approval of the rates and conditions of service as set forth within the Agreement pursuant to S.C. Code Ann. 58-27-830 and 10 S.C. Code Ann. Reg. 103-303. As stated previously, the term of the Agreement is 35 years unless it is terminated pursuant to the applicable terms by one of the parties.

10. DEC proposes that the revenues from the sale of steam from the Agreement be credited back to its electric customers.

12. Since the CHP Facility will be designed for operation at a capacity of 16 megawatts, the proposed CHP facility is not a "major utility facility" requiring a Utility Facility Siting and Environmental Protection Act Certificate pursuant to S.C. Code § 58-33-10 *et seq.*

13. CHP generation has the potential to be the lowest cost generation asset on the grid while producing significantly less CO_2 and NO_x emissions. It provides two revenue streams from one generator. The CHP Facility will provide improved reliability for the electric grid and for customers. In addition, CHP generation provides economic development opportunities for South Carolina to bring new manufacturing jobs to the State and by reducing energy costs for new or expanding industries.

12. DEC requests that this application be considered and approved without notice being required and without a hearing. The application is for approval of a contract to provide steam heat to one customer and will not affect other customers. Research of the Commission's files indicates that similar steam contracts were approved in Docket No. 1996-049-E (Order No. 96-192) and

Docket No. 1996-189-E (Order No. 96-433) and it does not appear that notice or a hearing was required in either docket.

WHEREFORE, for the foregoing reasons, and for good cause shown, the Company petitions this Commission for a Certificate of Public Convenience and Necessity to provide steam (heat) service to Clemson and for approval of the Agreement between Clemson and DEC.

Respectfully submitted this the 21st day of February, 2017.

Heather Shirley Smith, Esq.
Deputy General Counsel
Duke Energy Business Services, LLC
40 West Broad St, Suite 690
Greenville, SC 29601
Telephone 864.370.5045
heather.smith@duke-energy.com

and

SOWELL, GRAY, ROBINSON, STEPP & LAFFITTE, LLC

s/Frank R. Ellerbe, III
Frank R. Ellerbe, III
Post Office Box 11449
Columbia, South Carolina 29211
Telephone: 803-227-1112
fellerbe@sowellgray.com

Attorneys for Duke Energy Carolinas, LLC

BEFORE
THE PUBLIC SERVICE COMMISSION OF
SOUTH CAROLINA

In the matter of: Duke Energy Carolinas, LLC's Application for a Certificate of Public Convenience and Necessity for the Provision of Steam (Heat) Service and for Approval of a Contract with Clemson University	)	**DUKE ENERGY CAROLINAS, LLC'S APPLICATION FOR A CPCN TO PROVIDE STEAM SERVICE AND FOR CONTRACT APPROVAL**

EXHIBIT A

STEAM SUPPLY AND PURCHASE AGREEMENT BETWEEN DUKE ENERGY CAROLINAS, LLC AND CLEMSON UNIVERSITY FEBRUARY 2, 2017

/A

EXECUTION FORM

STEAM SUPPLY AND PURCHASE AGREEMENT

Between

DUKE ENERGY CAROLINAS, LLC

as Seller

and

CLEMSON UNIVERSITY

as Buyer

Dated as of February 2, 2017

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STEAM SUPPLY AND PURCHASE AGREEMENT

This STEAM SUPPLY AND PURCHASE AGREEMENT (this "Agreement") is made and entered into effective as of February ___, 2017 (the "Effective Date") between Duke Energy Carolinas, LLC, a North Carolina limited liability company ("Seller"), and Clemson University, a body politic under the laws of the State of South Carolina ("Buyer"). Buyer and Seller are sometimes referred to herein individually as a "Party" and collectively as the "Parties."

RECITALS

WHEREAS, Buyer uses steam for purposes of heating classroom, library, office, administrative, and other buildings on its university campus;

WHEREAS, Buyer desires to engage Seller to convert water into steam that Buyer can purchase from Seller for process use in Buyer's facilities and is willing to lease to Seller a site on Buyer's property at which Seller can produce and provide such steam; and

WHEREAS, Seller is willing to be so engaged and accordingly is willing to construct and own at such site a combined heat and power facility consisting of a natural gas fired turbine and associated electric generator, along with an associated heat recovery steam generator and supplementary direct fired natural gas burner, which will be capable of providing approximately 125 k-lb./hour of steam in accordance with the terms and conditions set forth in this Agreement;

AGREEMENT

NOW, THEREFORE, in consideration of the mutual covenants and promises set forth herein and other good and valuable consideration, the receipt and adequacy of which are hereby acknowledged, and intending to be bound hereby, the Parties hereby agree as follows:

ARTICLE 1
DEFINITIONS AND USAGE

1.1 Definitions. As used in this Agreement, the following capitalized terms have the meanings set forth below.

"Affected Party" has the meaning set forth in Section 12.5(a).

"Affiliate" means, with respect to any specified Person (other than a natural person), any other Person who, directly or indirectly, through one or more intermediaries, owns or controls, is under common ownership or control with, or is owned or controlled by, such Person. For purposes of the foregoing, "control", "controlled by", and "under common control with" with respect to any Person will mean the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of such Person, whether through the ownership of voting securities, by contract, of otherwise. "Affiliate" will include, in the case of Buyer, any foundation created for the benefit of Buyer.

"Agreement" has the meaning set forth in the first paragraph of this Agreement.

"Bankrupt" means, with respect to a Party or other entity, that such Party or other entity: (i) is dissolved (other than pursuant to a consolidation, amalgamation or merger); (ii) becomes insolvent or is unable to pay its debts or fails (or admits in writing its inability) generally to pay its debts as they become due; (iii) makes a general assignment, arrangement or composition with or for the benefit of its creditors; (iv) has instituted against it a proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditor's rights, or a petition is presented for its winding-up or liquidation, which proceeding or proceeding is not dismissed, stayed or vacated within 30 days thereafter; (v) commences a voluntary proceeding seeking a judgment of insolvency or bankruptcy or any other relief under any bankruptcy or insolvency law or other similar law affecting creditors' rights; (vi) seeks or consents to the appointment of an administrator, provisional liquidator, conservator, receiver, trustee, custodian or other similar official for it or for all or substantially all of its assets; (vii) has a secured party take possession of all or substantially all of its assets, or has a distress, execution, attachment, sequestration or other legal process levied, enforced or sued on or against all or substantially all of its assets; (viii) causes or is subject to any event with respect to it which, under the applicable Laws of any jurisdiction, has an analogous effect to any of the events specified in clauses (i) to (vii) inclusive; or (ix) takes any action in furtherance of, or indicating its consent to, approval of, or acquiescence in, any of the foregoing acts.

"Business Day" means any day except a Saturday, Sunday or a Federal Reserve Bank holiday. A Business Day will open at 8:00 a.m. and close at 5:00 p.m., at the location of the Facility.

"Buyer" has the meaning set forth in the first paragraph of this Agreement.

"Buyer Conditions Precedent" has the meaning set forth in Section 2.3.

"Change in Law" means any binding, written change after the Effective Date in the judicial or administrative interpretation of, or adoption after the Effective Date of, any Environmental Law or Law relating to Taxes, which is inconsistent or at variance with any Law in effect on the Effective Date; *provided, however*, that a Change in Law will not include any change or adoption of any Law with respect to (a) Taxes assessed on income, profits, revenues or gross receipts, (b) Taxes that vary the compensation, benefits, or amounts to be paid to or on behalf or on account of employees, or (c) organization, existence, good standing, qualification, or licensing in any jurisdiction.

"Change in Law Costs" means the actual and verifiable change (whether on a one-time or cumulative basis) in the Affected Party's operating costs for or in connection with the purchase or sale of Steam under this Agreement (and not in any event including any change in operating costs for or in connection with the purchase or sale of electric energy or any other product or service from the Facility outside of this Agreement) that results from a Change in Law, excluding costs of any applicable greenhouse gas emissions credits or offsets (which are subject to the provisions of Section 12.5(c)); *provided, however*, that "Change in Law Costs" will not include any costs or expenses caused by or resulting from any failure by the Affected Party to comply, or delay by the Affected Party in complying, with any Governmental Rule. "Change in Law Costs" include any additional amounts of federal, state or local Taxes that the Affected

Party is required to pay as a result of reimbursement by the other Party of any Change in Law Costs under or pursuant to this Agreement.

"Change in Law Threshold Amount" means the amount of $15 million.

"CHP" means combined heat and power.

"Claim" means any demand, claim, action, suit, investigation, arbitration or proceeding (whether at law or in equity) before or by any Governmental Authority or by any other Person.

"Claiming Party" has the meaning set forth in Section 12.1.

"Commercial Operation Date" means the date identified in written notice from Seller to Buyer as the date upon which the Facility, including the natural gas supply thereto, is complete, and deliveries of Steam (other than test deliveries) will commence under this Agreement.

"Condensate" means the Steam condensate supplied by Buyer to the Facility for use by Seller in the production of Steam, in accordance with the specifications set forth on Exhibit A.

"Condensate Delivery Point" means the physical point at which interconnection for delivery of Condensate is made between the Condensate systems of the Host and the Facility, as set forth on Exhibit B.

"Condensate Interconnection Facilities" means those physical facilities of a quality and type reasonably required for the receipt and delivery of Condensate, including service stop valves, meter stop valves, meter supports, meter(s), pipe system(s), pipeline(s), and other facilities of a quality and type reasonably required to effectuate the purposes of this Agreement.

"Confidential Information" has the meaning set forth in Section 17.1.

"Contract Price" means the price to be paid by Buyer to Seller for Steam, as set forth in Exhibit C.

"Contract Year" means each calendar year during the Term, commencing on the Commercial Operation Date, provided that if the first and last Contract Years are not full calendar years, the first Contract Year will mean the period from the Commercial Operation Date to December 31 of such calendar year, and the last Contract Year will mean the period from January 1 of the last Contract Year through the last day of the Term.

"Credit Rating" means (i) with respect to any entity other than a financial institution, the current (A) rating issued or maintained by S&P or Moody's with respect to such entity's long-term senior, unsecured, unsubordinated debt obligations (not supported by third party credit enhancements) or (B) corporate credit rating or long-term issuer rating issued or maintained with respect to such entity by S&P or Moody's, or (ii) if such entity is a financial institution, the ratings issued or maintained by S&P or Moody's with respect to such entity's long-term, unsecured, unsubordinated deposits.

"Defaulting Party" has the meaning set forth in Section 14.1.

"Delivery Point" means any of the Steam Delivery Point and the Condensate Return Delivery Point.

"Delivery Term" means the period of time commencing on the Commercial Operation Date and ending on the expiration or earlier termination of the Term.

"Disclosing Party" has the meaning set forth in Section 17.1(a).

"Dispute" has the meaning set forth in Section 18.4(a).

"Early Termination Date" has the meaning set forth in Section 14.3(a).

"Easement Areas" has the meaning set forth in the Ground Lease.

"Easements" has the meaning set forth in the Ground Lease.

"Effective Date" has the meaning set forth in the first paragraph of this Agreement.

"Environmental Credits" means greenhouse gas offsets, "carbon credits," emissio credits, emission reduction credits, renewable energy credits, renewable energy certificates, environmental attributes, environmental credits, "green" credits, "green" certificates, emissions allowances, tax credits, or other similar credits or certificates.

"Environmental Laws" means all Laws relating to (i) facility siting, land use and environmental matters, (ii) the control of any pollutant, or protection of the air, water, or land, (iii) solid, gaseous or liquid waste generation, handling, treatment, storage, disposal or transportation, (iv) exposure to hazardous, toxic or other harmful substances, and (v) the protection and enhancement of the environment. Environmental Laws will include the Clean Air Act, 42 U.S.C. §7401 et seq. ("CAA"), the Clean Water Act, 33 U.S.C. § 1251 et seq. ("CWA"), the National Environmental Policy Act, 42 U.S.C. § 4321 et seq., the Endangered Species Act, 16 U.S.C. § 1531 et seq., the Resource Conservation Recovery Act, 42 U.S.C. §6901 et seq. ("RCRA"), the Safe Drinking Water Act. 42 U.S.C. §300f et seq., the Comprehensive Environmental Response, Compensation, and Liability Act as amended by the Superfund Amendments and Reauthorization Act, 32 U.S.C. §9601 et seq. ("CERCLA"), the Federal Insecticide, Fungicide and Rodenticide Act, 7 U.S.C. § 136 et seq., the Hazardous Materials Transportation Act, 49 U.S.C. §1801 et seq., the Toxic Substances Control Act, 15 U.S.C. §2601 et seq. ("TSCA"), and the Emergency Planning and Community Right-to-Know Act, 42 U.S.C. §11001 et seq., any state or local Laws relating to Permits, local land use control ordinances or similar Laws, and any state or local Laws implementing or substantially equivalent to the foregoing federal requirements.

"Environmental Noncompliance" means any violation of Environmental Laws, including: (a) the discharge, emission, release or threatened release (as such term is used in CERCLA, RCRA, the CWA, the CAA or other similar Environmental Laws) of any Hazardous Materials in violation of any Environmental Laws; (b) any noncompliance with Environmental Laws regarding the construction, modification, operation and maintenance of physical structures, equipment, processes or facilities; (c) any noncompliance with federal, state or local requirements governing occupational safety and health related to Hazardous Materials; (d) any

facility operations, procedures, designs, or other matters which do not conform to the statutory or regulatory requirements of Environmental Laws, including the CAA, the CWA, the TSCA and the RCRA; (e) the failure to have obtained or to maintain in full force and effect Permits, variances or other authorizations necessary for the legal operation of any equipment, process, facility or any other activity, to the extent required for compliance with Environmental Laws; or (f) the operation of any facility, process, or equipment in violation of any Permit condition, schedule of compliance, administrative or court order, to the extent required for compliance with Environmental Laws.

"Event of Default" has the meaning set forth in Section 14.1.

"Existing Environmental Conditions" means any environmental conditions, circumstances or other matters of fact pertaining to, relating to or otherwise affecting the environment and in existence prior to the Effective Date, including any environmental pollution, contamination, degradation, damage or injury caused by, related to, or arising from or in connection with (i) the presence, use, handling, storage, treatment, recycling, generation, transportation, release, spilling, leaking, pumping, pouring, emptying, discharging, injecting, escaping, leaching, disposal (including the abandonment or discarding of barrels, containers and other closed receptacles containing any Hazardous Materials), dumping or threatened release of Hazardous Materials in connection with the ownership, possession, construction, improvement, use or operation of the Site prior to the Effective Date, (ii) the offsite transport prior to the Effective Date of Hazardous Materials from the Site, or the treatment, storage or disposal of Hazardous Materials transported from the Site to another site prior to the Effective Date and (iii) the release prior to the Effective Date of Hazardous Materials from the Site into the atmosphere or any water course or body of water not included in the Site.

"Facility" means (i) the CHP facility to be constructed by Tenant on the Site as such facility is generally described on Exhibit B attached hereto, including the HRSG, and (ii) all other equipment related to the foregoing owned by Seller and located on the Site or the Easement Areas, and (iii) any modifications or additions to any of the foregoing.

"Force Majeure Event" means any event, condition or circumstance that: (i) is not a consequence or result of the fault or negligence of the affected Party or its Affiliates, (ii) cannot, despite the exercise of commercially reasonable efforts by the affected Party, be controlled, prevented, avoided or removed, and (iii) prevents in whole or in part performance of the obligations of the affected Party under this Agreement. The following events, the list of which is not exhaustive, will be considered to be Force Majeure Events to the extent they satisfy the requirements of the foregoing sentence: (a) lightning, earthquake, hurricane, storm, wind, drought, abnormal weather condition, or other similar natural calamities or acts of God; (b) fire, explosion or chemical contamination; (c) epidemic, quarantine restriction or plague; (d) act of war (declared or undeclared), invasion, armed conflict or act of foreign enemy, blockage, economic sanction or embargo, revolution, sabotage, riot, insurrection, civil unrest or disturbance, military or guerilla action, banditry, terrorist activity or a threat of terrorist activity, or tribal, religious or sectarian unrest; (e) radioactive contamination (and associated clean-up activities); (f) damage to or failure of the Facility or the Host caused by a Person other than the affected Party; and (g) other acts or occurrences beyond the control of the affected Party, including the act or omission of Governmental Authorities (to the extent such act or omission is

not a result of the failure of the affected Party to act on any lawful request of such Governmental Authority). "Force Majeure Event" expressly excludes: (w) governmental action (including any binding order of any Governmental Authority) that such Party could have prevented by compliance with applicable Law; (x) a Party's financial inability to perform, (y) changes in market prices for products or services produced by a Party, (z) any failure to perform, and the effects of such failure, that could have been prevented, overcome or remedied by the exercise of reasonable efforts by the Party claiming excused performance by reason of a Force Majeure Event, or (aa) global economic or financial market conditions.

"GAAP" means United States generally accepted accounting principles consistently applied.

"Governmental Authority" means any national, state, provincial, local, tribal or municipal government, any political subdivision thereof or any other governmental, regulatory, quasi-governmental, judicial, public or statutory instrumentality, authority, body, agency, department, bureau, or entity with authority to bind a Party at law; *provided, however*, that "Governmental Authority" will not in any event include any Party.

"Ground Lease" means the Ground Lease and Easement Agreement between Seller, as Tenant, and Buyer, as Landlord, of even date herewith, pursuant to which Seller leases the Site.

"Hazardous Materials" means any chemicals, materials, substances, or items in any form, whether solid, liquid, gaseous, semisolid, or any combination thereof, whether waste materials, raw materials, chemicals, finished products, by-products, or any other materials or articles, which are listed or regulated as hazardous, toxic or dangerous or as waste or a contaminant, or are otherwise listed or regulated, or for which liability or standards of care are imposed, under any Environmental Law, including petroleum products, asbestos, PCBs, coal combustion by-products, urea formaldehyde foam insulation, lead-containing paints or coatings, and any substances included in the definition of "hazardous debris," "hazardous substances," "hazardous materials," "hazardous wastes," "toxic substances," "pollutants," "contaminants" or words of similar import, under any Environmental Laws.

"Host" means the facility located in Pickens County, South Carolina, and all appurtenant structures, fixtures, improvements, equipment and other appurtenant personal property interests now or hereafter owned or leased by Buyer or any Affiliate of Buyer on the Host Premises, including the water supply and steam delivery systems between the Host and the applicable Delivery Points and any and all other improvements installed on the Host Premises from time to time.

"Host Premises" means all premises other than the Site that are owned or leased by Buyer or its Affiliates and at which the Steam will be used or through which the Steam will be delivered.

"HRSG" means the heat recovery steam generator located within the Facility.

"IFRS" means the International Financial Reporting Standards as in effect from time to time.

"Indemnified Party" has the meaning set forth in Section 16.1.

"Indemnifying Party" has the meaning set forth in Section 16.1.

"Interconnection Facilities" means each of the Condensate Interconnection Facilities and Steam Interconnection Facilities.

"Interest Rate" means, for any date, the lesser of (a) the per annum rate of interest equal to the prime lending rate as may from time to time be published in *The Wall Street Journal* under "Money Rates" on such day (or if not published on such day, on the most recent preceding day on which published), plus 2%; and, (b) the maximum rate permitted by applicable Law.

"Landlord" means Buyer as Landlord under the Ground Lease.

"Laws" means all common law, laws, statutes, treaties, rules, orders, codes, ordinances, standards, regulations, restrictions, official guidelines, policies, directives, interpretations, Permits or like action having the effect of law of any Governmental Authority.

"Losses" has the meaning set forth in Section 16.1.

"Make-Up Water" means raw water procured by Seller, in the quantity set forth in Section 6.2, for the production of Steam under this Agreement.

"Merger Event" means, with respect to a Party or other entity, that such Party or other entity consolidates or amalgamates with, or merges into or with, or transfers all or substantially all of its assets to, another entity, and (i) the resulting, surviving or transferee entity fails, at the time of such consolidation, amalgamation, merger or transfer, to assume each and all of the obligations of such Party or other entity under this Agreement, either by operation of Law or pursuant to an agreement reasonably satisfactory to the other Party, (ii) the Credit Rating (from each of S&P and Moody's, as applicable) of such of the resulting, surviving or transferee entity is not equal to or higher than the Credit Rating of such Party or other entity, or (iii) the resulting, surviving or transferee entity is not rated by at least one of S&P and Moody's.

"Metering Tolerances" means a band between +1% and -1%.

"Monthly Invoice" has the meaning set forth in Section 4.2.

"Monthly Payment" has the meaning set forth on Exhibit C.

"Moody's" means Moody's Investor Services, Inc. and any successor thereto.

"Non-Defaulting Party" means, with respect to any Event of Default, the Party that is not the Defaulting Party.

"Order" means any order, ruling, decision, judgment, writ, injunction, decree, settlement, stipulation or award of any Governmental Authority.

"Party" or "Parties" has the meaning set forth in the first paragraph of this Agreement and includes any permitted assignee of a Party.

"Permit" means the written permission or authorization granted by a Governmental Authority, including all licenses, permits, decrees, franchises, consents, authorizations, approvals, ratifications, certifications, registrations, exemptions, variances, exceptions, waivers, extensions and similar consents granted or issued by any Governmental Authority.

"Permitted Transaction" means any of the following: (a) transactions among Affiliates of Seller or Buyer (or, in the case of Buyer, transactions among foundations created for or to benefit the Buyer), including any corporate reorganization, merger, combination or similar transaction or transfer of assets or ownership interests involving Seller, Buyer or their Affiliates; (b) the direct or indirect transfer of shares of, or equity interests in, Seller to a tax equity investor; or (c) a transfer of the Facility packaged with all or substantially all of the assets of Seller's Ultimate Parent Entity; *provided* that the entity that operates the Facility following such transfer is (or contracts with) a Qualified Operator.

"Person" means and includes an individual, a partnership, a joint venture, a corporation, a union, a limited liability company, a trust, an unincorporated organization, Governmental Authority or any other separate legal entity recognized pursuant to law.

"Planned Outage" means a scheduled outage that may require removal of the Facility or the Host, in whole or in part, from service in order to perform specified work on specific components of the Facility. A Planned Outage has a pre-determined start date, an estimated duration, which may last for several weeks, and occurs as scheduled in a notice given by the Seller (with respect to the Facility) or Buyer (with respect to the Host) to the other Party in accordance with Section 8.2.

"Prudent Operating Practices" means, with respect to the Facility, the practices, methods and acts generally engaged in or approved by the CHP industry segment supplying thermal energy and electric energy to institutional, commercial, or industrial customers and selling electric energy to public utilities in the southeastern United States for similar facilities during a particular time period, or any of such practices, methods, and acts, that, in the exercise of reasonable judgment in light of the facts known or that reasonably should be known at the time a decision is made, would be expected to accomplish the desired result in a manner consistent with applicable Law, reliability, safety, environmental protection, economy and expedition, and which practices, methods and acts are consistent with any applicable operation and maintenance standards recommended by the Facility's equipment suppliers and manufacturers, operational limits. Without limiting the foregoing, Prudent Operating Practices are not intended to be limited to the optimum practices, methods or acts, to the exclusion of all others, but rather to include a spectrum of practices, methods or acts generally acceptable in the region during the relevant period in light of the circumstances.

"Qualified Operator" means an operator of generation facilities of a similar type and size as the Facility that is nationally recognized and that demonstrates to Buyer's reasonable satisfaction that it and the personnel who will be operating the Facility have sufficient experience to successfully and effectively operate the Facility in accordance with the terms and conditions

of this Agreement, including a minimum of 3 years' experience in the operation of one or more CHP or other gas-fired generating facilities, and demonstrates to Buyer's reasonable satisfaction that the operator has the financial capability to fulfill Seller's obligations hereunder.

"Receiving Party" has the meaning set forth in Section 17.1(a).

"Representatives" means, means, with respect to a Party, (i) the directors, officers, managers, employees, financial advisors, accountants, auditors, legal counsel, consultants and other representatives of such Party or its Affiliates and (ii) such Party's or its Affiliates' current or potential lenders, sources of funding or rating agencies.

"Required Credit Rating" means, in the case of any Person, that such Person's long-term senior, unsecured, unsubordinated debt obligations (not supported by third party credit enhancements) are rated by at least one of S&P and Moody's, and that such Person has a Credit Rating of (i) if rated by only one of Moody's or S&P, a Credit Rating of "Baa2" or higher by Moody's or "BBB-" or higher by S&P, or (ii) if rated by both Moody's and S&P, a Credit Rating of "Baa2" or higher by Moody's and "BBB-" or higher by S&P.

"S&P" means the Standard & Poor's Rating Group (a division of McGraw-Hill, Inc.) or its successor.

"SCPSC" means the South Carolina Public Service Commission or its successor.

"Seller" has the meaning set forth in the first paragraph of this Agreement.

"Seller Conditions Precedent" has the meaning set forth in Section 2.4.

"Site" has the meaning set forth in the Ground Lease.

"State Regulatory Approval" means a final, non-appealable written order from the SCPSC or any other state public utilities commission having jurisdiction that, as applicable, (i) grants a certificate of public convenience and necessity or equivalent regulatory approval for the Facility, (ii) determines that the costs incurred by Seller for the generation and delivery of electric power from the Facility are recoverable from Seller's retail electric customers pursuant to applicable Law, or (iii) approves Seller as a steam corporation for purposes of the sale of Steam under this Agreement.

"Steam" means the steam produced by the Facility and delivered to the Steam Delivery Point in accordance with the specifications on Exhibit A.

"Steam Delivery Point" means the physical point at which interconnection for delivery of Steam is made between the Steam systems of the Host and the Facility, as set forth on Exhibit B.

"Steam Flow Meter" has the meaning set forth in Section 5.1(a).

"Steam Interconnection Facilities" means those physical facilities of a quality and type reasonably required for the receipt and delivery of Steam, including service stop valves, meter

stop valves, meter supports, meter(s), pipe system(s), pipeline(s), and other facilities of a quality and type reasonably required to effectuate the purposes of this Agreement.

"Subcontractor" has the meaning set forth in Section 13.3(a).

"Substation Easement Agreement" means an easement agreement under which Buyer would grant to Seller an easement for the development, construction, ownership, operation, and maintenance of a utility substation through which electric service would be provided to Buyer's university campus and the Facility would interconnect with the electric transmission system.

"Target Commercial Operation Date" means April 30, 2019 or any date to which the Target Commercial Operation Date may be extended in accordance with the provisions of this Agreement.

"Taxes" means all present and future license, documentation, recording and registration fees, all taxes (including income, gross receipts, unincorporated business income, payroll, sales, use, privilege, personal property (tangible and intangible), real estate, excise and stamp taxes), levies, imports, duties, assessments, fees (customs or otherwise), charges and withholdings of any nature whatsoever, and all penalties, fines, additions to tax, and interest imposed by any Governmental Authority.

"Tenant" means Seller as Tenant under the Ground Lease.

"Term" has the meaning set forth in Section 2.1.

"Termination Payment" means the applicable amount set forth in Exhibit D.

"Ultimate Parent Entity" means, with respect to Seller, Duke Energy Corporation.

"Utilities" has the meaning set forth in the Ground Lease.

1.2 Interpretation.

(a) Words singular and plural will be deemed to include the other, and pronouns having masculine or feminine gender will be deemed to include the other.

(b) Unless expressly stated otherwise, (i) reference to any Person includes such Person's successors and assigns but, in the case of a Party, only if such successors and assigns are permitted by this Agreement, (ii) reference to a Person in a particular capacity excludes such Person in any other capacity or individuality, and (iii) reference to a Governmental Authority includes any Person succeeding to its functions and capacities.

(c) Any reference in this Agreement to any Section, Exhibit means and refers to the Section contained in, or Exhibit attached to, this Agreement.

(d) Other grammatical forms of defined words or phrases have corresponding meanings.

(e) A reference to writing includes typewriting, printing, lithography, photography, electronic mail, and any other mode of representing or reproducing words, figures or symbols in a lasting or visible form.

(f) Unless otherwise provided, a reference to a specific time for the performance of an obligation is a reference to that time in the place where that obligation is to be performed.

(g) A reference to a document, code, contract or agreement, including this Agreement, includes a reference to that document, code, contract or agreement as novated, amended, modified, revised, supplemented, replaced or restated from time to time in accordance with the relevant provisions thereof. Any term defined or provision incorporated in this Agreement by reference to another document, instrument or agreement will continue to have the meaning or effect ascribed thereto whether or not such other document, instrument or agreement is in effect.

(h) Unless otherwise expressly provided for as set forth herein, the term "day" will mean a calendar day, and whenever an event is to be performed or payment, act, matter or thing hereunder would occur on a day that is not a Business Day, then such event will be performed and such payment, act, matter or thing will, unless otherwise expressly provided for herein, occur on the next succeeding Business Day.

(i) Relative to the determination of any period of time, "from" means "from and including," "to" means "to but excluding," and "through" means "through and including."

(j) Where reference is made to an applicable Law, such reference, to give meaning to the intent of the Parties hereto, will be deemed to include all prior and subsequent enactments, amendments and modifications pertaining thereto.

(k) Any reference to the words "include and including" will be interpreted to mean "including without limitation," and any reference to the words "hereof," "hereunder," or "herein" or words of similar import will refer to this Agreement as a whole and to a particular Article, Section, subsection, clause or other subdivision hereof.

(l) References to "or" will be deemed to be disjunctive but not necessarily exclusive (*i.e.*, unless the context dictates otherwise, "or" will be interpreted to mean "and/or" rather than "either/or").

(m) All monetary references contained herein refer to U.S. dollars.

(n) All accounting terms used herein will be construed in accordance with GAAP (or IFRS if required under applicable Law) unless the context or use requires a different interpretation. Any financial statements provided pursuant to this Agreement will be prepared in accordance with GAAP (or IFRS if required under applicable Law).

(o) Any words or phrases (including electrical, natural gas and CHP industry terms) not otherwise defined herein will have their common meanings.

ARTICLE 2
TERM OF AGREEMENT; TERMINATION

2.1 Term. The term of this Agreement (the "Term") will commence on the Effective Date and will remain in effect for a period of 35 years from the Commercial Operation Date, unless earlier terminated in accordance with the provisions of this Agreement.

2.2 Termination Prior to Target Commercial Operation Date.

(a) Seller may terminate this Agreement, without any liability for or as a result of such termination except as provided in Section 2.2(d), by written notice to Buyer on or before the Target Commercial Operation Date if:

(i) Any of the Seller Conditions Precedent set forth in Section 2.4 are not satisfied or waived by Seller;

(ii) Seller (A) receives (1) a written order rejecting any State Regulatory Approval or imposing conditions on any State Regulatory Approval that Seller, in its sole and absolute discretion, determines are unsatisfactory, or (2) any determination rejecting or attaching material adverse conditions on any Permit required under applicable Law for Seller's performance of its obligations hereunder, or (B) reasonably determines that it will be unable to secure, through reasonable diligence and effort, any applicable State Regulatory Approval or any Permits required under applicable Law to construct, own and operate the Facility or any Interconnection Facilities, lease the Site and provide the Steam to be provided by Seller to Buyer hereunder, including the Permits listed on Exhibit E; or

(iii) Seller receives a final, unappealable Order from a Governmental Authority that prohibits or materially adversely affects the transactions contemplated in this Agreement or the Ground Lease.

(b) Subject to Seller's rights to extend the Target Commercial Operation Date under Section 2.2(c), Buyer may terminate this Agreement, without any liability for or as a result of such termination except as provided in Section 2.2(e), by written notice to Seller on or before the Target Commercial Operation Date if any of the Buyer Conditions Precedent set forth in Section 2.3 are not satisfied or waived by Buyer on or before the Target Commercial Operation Date.

(c) Seller will have a right to extend the original Target Commercial Operation Date as follows:

(i) If Seller makes a good faith determination that it will be unable to secure, through reasonable diligence and effort, any applicable State Regulatory Approval or any Permits required under applicable Law to construct, own and operate the Facility or any Interconnection Facilities, lease the Site and provide the Steam to be provided by Seller to Buyer hereunder, including the Permits listed on Exhibit E, Seller may extend the original Target Commercial Operation

Date for a period of up to 12 months by written notice to Buyer prior to the original Target Commercial Operation Date; *provided* that Seller exercises diligent and commercially reasonable efforts to secure any such State Regulatory Approval or Permit;

(ii) If a Force Majeure Event occurs prior to the original Target Commercial Operation Date, Seller may extend the original Target Commercial Operation Date for a period equal to the duration of such Force Majeure Event plus an additional 30 days; *provided*, *however*, that in no event may such extension exceed a period of 12 months.

(d) If this Agreement is terminated solely as a result of any failure of the Seller Condition Precedent provided in Section 2.4(a) or as a result of any failure of any of the Buyer Conditions Precedent provided in Sections 2.3(e) or 2.3(f), Seller will reimburse Buyer for all of the actual and reasonable costs and actual and reasonable expenses incurred by Buyer for or in connection with the Interconnection Facilities prior to such termination.

(e) If this Agreement is terminated solely as a result of any failure of the Buyer Condition Precedent provided in Section 2.3(a) or as a result of any failure of any of the Seller Conditions Precedent provided in Sections 2.4(b) or 2.4(c), Buyer will reimburse Seller for all of the actual and reasonable costs and actual and reasonable expenses incurred by Seller for or in connection with the Interconnection Facilities prior to such termination.

2.3 Buyer Conditions Precedent. The following will be the "Buyer Conditions Precedent":

(a) Approval of this Agreement by the Board of Trustees of Buyer;

(b) The occurrence of the Commercial Operation Date, and the completion by Seller of, and operability of, any and all Interconnection Facilities necessary for the delivery of Steam to Buyer at the applicable Delivery Points and necessary for the receipt of Condensate from Buyer at the applicable Delivery Points;

(c) Receipt by Seller of all applicable State Regulatory Approvals and all Permits required under applicable Law to construct, own and operate the Facility or any Interconnection Facilities, lease the Site and provide the Steam to be provided by Seller to Buyer hereunder, including the Permits listed on Exhibit E;

(d) Receipt by Buyer of all Permits required for the performance by it of its obligations under this Agreement and the Ground Lease;

(e) Execution and delivery of the Ground Lease by Seller; and

(f) The absence of any Event of Default or facts and circumstances that, with the passage of time or giving of notice, would give rise to an Event of Default with respect to Seller hereunder.

2.4 Seller Conditions Precedent. The following will be the "Seller Conditions Precedent":

(a) Approval of this Agreement by the Board of Directors of Seller;

(b) Execution and delivery of the Ground Lease by Buyer; and

(c) The absence of any Event of Default or facts and circumstances that, with the passage of time or giving of notice, would give rise to an Event of Default with respect to Buyer hereunder.

2.5 Right to Terminate for Failure to Execute Substation Easement Agreement. Either Party may terminate this Agreement, without any liability for or as a result of such termination, by written notice to the other Party on or before September 15, 2017 if the form of the Substation Easement Agreement has not been agreed to and the Substation Easement Agreement has not been executed and delivered and recorded on or before August 31, 2017.

ARTICLE 3
PURCHASE AND SALE OF STEAM

3.1 Seller's Obligations to Produce and Deliver Steam.

(a) During the Delivery Term, Seller will use Condensate and Make-Up Water to produce Steam at the Facility, in an amount each hour equal to the maximum mass volume of Steam that the Facility is reasonably capable of producing during such hour from such Condensate and Make-Up Water, and will deliver and sell such Steam to Buyer at the Steam Delivery Point.

(b) All Steam delivered by Seller to Buyer under this Agreement will be required to meet the Steam specifications set forth in Exhibit A.

(c) Seller will at all times during the Delivery Term, at its sole cost and expense, operate and maintain the Facility in accordance with Prudent Operating Practices and in compliance with applicable Law.

3.2 Buyer's Obligations to Take and Pay for Steam.

(a) During the Delivery Term, Buyer will receive and purchase all Steam produced by the Facility and delivered to the Steam Delivery Point.

(b) Buyer will have no obligation to take or pay Seller for any Steam that fails to meet the Steam specifications set forth in Exhibit A. If Buyer rejects nonconforming Steam, the responsibility to dispose of such nonconforming Steam will remain with Seller. Notwithstanding the foregoing, if Buyer accepts nonconforming Steam (whether or not it has knowledge of the characteristics that make the same nonconforming), then it will be responsible for paying for such Steam on the same basis as if such Steam had conformed to the applicable specifications set forth in Exhibit A.

(c) Buyer will not use, or permit any other Person to use, Steam delivered to Buyer from the Facility for purposes of generating electric energy for use by any Person other than for use at the Host by Buyer, Clemson University Foundation, Inc., Clemson University Real Estate Foundation, Inc., Clemson University Research Foundation, Inc., Clemson University Land Stewardship Foundation, Inc., IPTAY, and their wholly owned subsidiaries.

(d) Buyer will not have any liability to Seller under this Agreement solely as a result of any failure of Buyer to take any Steam that Buyer is otherwise obligated to take hereunder, *provided* that Buyer pays for all such Steam in accordance with the requirements of this Agreement.

(e) Nothing in this Agreement shall be construed as to require Buyer to use Steam in connection with newly constructed buildings or in renovated buildings which are designed and configured by Buyer to use alternatives to Steam.

3.3 Transfer of Title and Risk of Loss.

(a) Title and risk of loss to Steam sold by Seller to Buyer hereunder will pass to Buyer at the Steam Delivery Point.

(b) Title and risk of loss to Condensate provided by Buyer to Seller hereunder will pass to Seller at the Condensate Delivery Point.

ARTICLE 4
PAYMENTS

4.1 Monthly Payment. For each calendar month during the Delivery Term in which Steam is delivered to the Steam Delivery Point, Buyer will pay Seller the Contract Price as determined in accordance with Exhibit C.

4.2 Monthly Invoices.

(a) On or before the tenth Business Day of each calendar month during the Delivery Term following the calendar month in which the Commercial Operation Date occurs, Seller will prepare an invoice showing the Monthly Payment payable by Buyer to Seller pursuant to this Agreement ("Monthly Invoice"). If the first Contract Year does not begin on the first day of the month, then the first Monthly Invoice will include a prorated calculation for the period from the Commercial Operation Date to the end of the month in which the Commercial Operation Date occurs.

(b) Monthly Invoices will present such information and calculations in reasonable detail for the preceding month as are reasonably required to support the calculation of the Monthly Payment, including supporting data for the calculations set forth on Exhibit C.

(c) Any amount payable under this Section 4.2 by one Party to the other Party will be due and payable within 30 days after receipt of the Monthly Invoice.

4.3 Taxes.

(a) Seller is liable for and will pay, or cause to be paid, or reimburse Buyer if Buyer has paid, all Taxes (including sales Tax) that are imposed or arise on Seller's side of the Delivery Points on the sale of Steam and receipt of Condensate under this Agreement.

(b) Buyer is liable for and will pay, or cause to be paid, or reimburse Seller if Seller has paid, all Taxes that are imposed or arise on Buyer's side of or at the Delivery Points on the purchase of Steam or provision of Condensate under this Agreement or use of any of the foregoing.

4.4 Environmental Credits. Seller will have the right to claim, bank, trade, sell, retire or retain any and all Environmental Credits related to the production of electric power or combined heat and power at the Facility; *provided, however*, that Buyer will retain all rights to Environmental Credits related to the Host or the generation of electric power therefrom, including any increased electric power generated at the Host enabled as a result of the transactions contemplated in this Agreement.

4.5 Late Payments. Any amounts payable by one Party to the other under this Agreement that are not paid when due will bear interest at the Interest Rate from the date such payment was due until the date such payment is actually paid.

4.6 Netting of Payments. The Parties hereby agree that they will discharge mutual undisputed debts and payment obligations due and owing to each in the same month through netting, in which case all amounts owed by each Party to the other Party for such monthly period, including any related payments calculated pursuant to Article 14, interest, and payments or credits, will be netted so that only the excess amount remaining due will be paid by the Party that owes it.

ARTICLE 5
METERING

5.1 Steam Monitoring and Metering.

(a) Seller will install, at its sole cost, (i) a meter at the Steam Delivery Point to determine the amount of Steam delivered to the Steam Delivery Point by Seller (the "Steam Flow Meter"); (ii) an instrument to measure Steam pressure located near the Steam Flow Meter; and (iii) an instrument to be installed near the Steam Flow Meter to measure the delivered Steam temperature. The Steam Flow Meter will continuously measure the flow of Steam delivered from the Facility to the Host. The Steam pressure instrument and the Steam temperature instrument will continuously measure the pressure and temperature of Steam delivered from the Facility to Buyer's Host. Seller will provide, at no cost to the Buyer, an access point to information from the Steam Flow Meter to enable Buyer to monitor the flow in as close to real time as is reasonably possible. Seller will operate, service, maintain, and replace (as needed), at Seller's expense, the Steam Flow Meter during the Delivery Term.

(b) The Steam Flow Meter will be sealed by both Parties, and such seal will be broken only by both Parties for inspection, testing or adjustment of the Steam Flow Meter.

5.2 Meter Testing.

(a) Seller will be responsible for reading, testing, servicing and maintaining the Steam Flow Meter. The Steam Flow Meter will conform to Prudent Operating Practices, and Seller will cause the Steam Flow Meter to be tested and calibrated no less often than once each Contract Year in accordance with Prudent Operating Practices. Seller will provide Buyer with not less than 14 days prior notice of such tests as well as with copies of all test reports and results as soon as they are available, and Buyer will have the right to have a representative present during any such test. Either Party may, not more frequently than once each Contract year, request a retest of the Steam Flow Meter if such Party has reasonable cause to believe that the accuracy of the Steam Flow Meter does not conform to Metering Tolerances. The Party requesting any such retest will pay for such retest and will provide the other Party with reasonable prior notice of such retest. Such other Party will have the right to have a representative present during such retest. The Party requesting any test or retest of the meters hereunder will pay the full cost and expense of conducting such test or retest, except that if any tested or retested meter is found to be not accurate within Metering Tolerances and such inaccuracy results in a payment being made to either Party, the Party making such payment will pay the full cost and expense of conducting such tests.

(b) If, for any reason, any meter is out of service or out of repair, or if any tested or retested meter is found to be not accurate within Metering Tolerances, Seller will promptly arrange for the repair, correction or replacement of the meter, at Seller's expense, and the Parties will use the measurements from (any) back-up meters to determine the amount of the inaccuracy. If there are no back-up meters or if the back-up meters are not in service or are found not to be accurate within the Metering Tolerances and the Parties cannot otherwise agree as to the amount of the inaccuracy, the inaccuracy will be determined, using as the basis therefor the best data available, (i) by calibration, test or mathematical calculation, if the percentage of inaccuracy is ascertainable by calibration, test or such calculation, or (ii) by such other method as is in accordance with Prudent Operating Practices in general use in the CHP industry.

(c) Any amounts payable by Buyer or to be refunded by Seller as a result of any faulty measurements by any meter that is not accurate within the Metering Tolerances will be paid or refunded by such Party within 30 days after discovery of such inaccuracy.

(d) Seller will provide Buyer with reasonable access to the Steam Flow Meter for the purpose of monitoring and verifying the accuracy of measurements made by such meters. Buyer will provide Seller with reasonable advance notice of any access by Buyer to the Steam Flow Meter, and Buyer and Seller will coordinate such access so as to minimize interruption to Seller's business activities. Seller will be entitled to have a representative accompany Buyer at all times during any such access by Buyer.

5.3 Meter Data. Seller will transmit to Buyer on a monthly basis an electronic data file containing the monthly metered quantity of Steam quantity for the relevant month at the same time that Seller provides Monthly Invoices under Section 4.2.

ARTICLE 6
CONDENSATE AND MAKE-UP WATER

6.1 Return of Condensate.

(a) Buyer will, at its sole cost and expense, return Condensate to Seller during the Delivery Term at the Condensate Delivery Point, solely for use at the Facility, in a mass quantity equivalent to at least 70% of the mass quantity of the Steam delivered to Buyer.

(b) Buyer will ensure that the Condensate supplied by Buyer to Seller under this Agreement meets the specifications set forth in Exhibit A, and is not contaminated with oil, excess rust, or other foreign substances that would make the Condensate unsuitable for production of Steam at the Facility. If any component of the Condensate becomes contaminated prior to return to Seller, Buyer will notify Seller promptly of such contamination and correct the source or cause of such contamination as quickly as practicable at Buyer's sole cost and expense. Buyer will pay any cost reasonably incurred by Seller to treat Condensate until such required corrections or modifications are made. If the cost of treating the Condensate exceeds its monetary value, Seller will, at its option, either dispose of such Condensate or require that Buyer dispose of such Condensate, in each case at Buyer's sole cost and expense.

(c) Buyer will obtain and maintain, at its sole cost and expense, any and all Permits required to procure and deliver Condensate in a quantity and quality sufficient to satisfy the requirements of Buyer under this Agreement. Seller will reasonably cooperate with and assist Buyer, at Buyer's cost and expense, in obtaining and maintaining such Permits.

6.2 Supply of Make-Up Water. Buyer will be responsible for procuring and delivering to Seller, at Buyer's sole cost and expense, any Make-Up Water that is required at any time to produce the maximum mass quantity of Steam that the Facility is reasonably capable of producing at such time.

ARTICLE 7
INTERCONNECTION FACILITIES

7.1 Steam Interconnection Facilities.

(a) Seller will, at its sole cost and expense, install, own, operate, maintain, repair, and, as necessary, replace any portion of the Steam Interconnection Facilities located on the Site.

(b) Buyer will, at its sole cost and expense, install, own, operate, maintain, repair, and, as necessary, replace any portion of the Steam Interconnection Facilities located on the Host Premises.

7.2 Condensate Interconnection Facilities.

(a) Seller will, at its sole cost and expense, install, own, operate, maintain, repair, and, as necessary, replace any portion of the Condensate Interconnection Facilities on the Site.

(b) Buyer will, at its sole cost and expense, install, own, operate, maintain, repair, and, as necessary, replace any portion of the Condensate Interconnection Facilities located on the Host Premises.

7.3 Approval of Changes in Interconnection Facility Locations. If Buyer wishes to change the location of any Interconnection Facilities located on the Host Premises, or if Seller wishes to change the location of any Interconnection Facilities located on the Site, the Party wishing to make such change will notify the other Party of such proposed change, and with provide with such notice sufficiently detailed specifications regarding the proposed change to permit the other Party to analyze appropriately the reasonably likely ramifications, including costs to such other Party, of such changes. The Party receiving such notice will approve the proposed changes or provide comments thereon within 15 days after receipt of such notice. If the Party receiving notice of the proposed change provides comments on any aspect of the proposed change, then the Parties will meet within 15 days after delivery of such comments to seek to resolve any issues between the Parties. Buyer and Seller will seek diligently and in good faith to reach agreement on any such matters. Whenever a Party's approval is required under the terms of this Section 7.3, such approval will not be unreasonably withheld or delayed; *provided, however*, that a Party will be deemed reasonable in withholding its approval of any changes in the location of any Interconnection Facilities that might interfere with or impair the safe and efficient operation of such Party's premises or facilities.

ARTICLE 8
OPERATIONS, SCHEDULING; NOTICE OF PLANNED OUTAGES

8.1 Notice Generally.

(a) Seller will provide notice to Buyer as soon as practicable of any outages of the Facility that are not Planned Outages and, as soon as practicable and when reliable information becomes available, provide Buyer with a schedule (date and hour of day) as to when the Facility is expected to return to service. Seller will provide Buyer with updates of the status and changes in the expected schedule of the Facility during such outages when such information becomes available in a reliable form.

(b) Buyer will provide notice to Seller as soon as practicable of any outages of the Host that are not Planned Outages and, as soon as practicable and when reliable information becomes available, provide Seller with a schedule (date and hour of day) as to when the Host is expected to return to service. Buyer will provide Seller with updates

of the status and changes in the expected schedule of the Host during such outages when such information becomes available in a reliable form.

8.2 Planned Outages.

(a) Not later than 90 days prior to the end of each Contract Year, Seller will prepare and provide to Buyer, for Buyer's review and comment, a proposed annual operating and maintenance plan for the next Contract Year, including proposed Planned Outage periods for the Facility and the Host. In scheduling Planned Outage periods for the Facility during each Contract Year, Seller will take into account the periods of Buyer's peak demand for Steam. To the extent commercially practicable, Seller will coordinate and schedule its Planned Outages of the Facility to coincide with the Buyer's Planned Outages of the Host. Seller will amend the proposed annual operating and maintenance plan to take into account any comments of Buyer regarding Planned Outage periods and expected downtime, and processes to address emergencies and unscheduled downtime, that are consistent with Prudent Operating Practices.

(b) Seller will provide notice to Buyer of any Planned Outages of the Facility that are not included in any annual operating and maintenance plan but that Seller reasonably determines are necessary in order to operate and maintain the Facility in accordance with Prudent Operating Practices and that will interfere with or reduce the provision of Steam to Buyer, *provided* that (i) Seller will give as much notice as is possible under the circumstances, and in any event at least 30 days' notice, of such Planned Outage, and (ii) such interference or reduction will be only to the extent and for the duration reasonably required by such outage or overhaul.

(c) Buyer will provide notice to Seller of any Planned Outages of the Host that are not included in any annual operating and maintenance plan but that Buyer reasonably determines are necessary in order to operate and maintain the Host in a commercially reasonable manner and that will interfere with or reduce the provision of Condensate or Utilities to Seller, *provided* that (i) Buyer will give as much notice as is possible under the circumstances, and in any event at least 30 days' notice, of a such Planned Outage, and (ii) such interference or reduction will be only to the extent and for the duration reasonably required by such outage or overhaul.

(d) The Parties acknowledge and agree that nothing in this Section 8.2 is intended to alter in any way any fixed monthly Steam payment obligation of Buyer as set forth in Exhibit C.

ARTICLE 9
PERMITS

9.1 Responsibility for Obtaining Permits.

(a) Each Party will, promptly following the Effective Date, make application for all Permits not previously applied for or obtained and required for such Party's performance of its obligations under this Agreement, including the Permits listed on

Exhibit E. Each Party will make timely and good faith efforts to secure all such Permits and will advise the other Party promptly after all such Permits have been received.

(b) A Party will not be deemed to be in breach of its obligations to obtain any Permit from any Governmental Authority to the extent that such Party is in good faith contesting the application, interpretation, order or other legal direction that would mandate a Party to obtain such Permit or the decision of any Governmental Authority with respect thereto.

9.2 Maintenance of Permits.

(a) Seller will maintain in effect during the Term all Permits that are required for the construction, development, operation, and maintenance of the Facility in accordance with the requirements of this Agreement and for the performance by Seller of its other obligations hereunder.

(b) Buyer will maintain in effect during the Term all Permits that are required for the construction, development, operation, and maintenance of the Host in accordance with the requirements of this Agreement and for the performance by Buyer of its other obligations hereunder.

ARTICLE 10
COMPLIANCE WITH APPLICABLE LAW

10.1 Compliance with Applicable Laws. Seller will at all times comply with all applicable Laws to which it or any part of the Facility may be subject. Buyer will at all times comply with all applicable Laws to which it or any part of the Host may be subject. A Party will not be deemed to be in breach of its obligations to comply with any applicable Laws to the extent that such Party is in good faith contesting the application, interpretation, order or other legal direction pursuant to which it, the Facility or the Host, as applicable, would be rendered subject to any such applicable Laws or the Order of any Governmental Authority with respect thereto.

10.2 Compliance with Orders. If a Party is subject to the jurisdiction of any Governmental Authority, then, subject to Section 2.3 or Section 2.4, as applicable, such Party agrees to abide by any and all applicable Orders issued by such Governmental Authority.

ARTICLE 11
REPRESENTATIONS AND WARRANTIES

11.1 Representations of Seller.

(a) Seller is a limited liability company duly formed, validly existing and in good standing under the Laws of its jurisdiction of formation. Seller is duly qualified or licensed to do business in each other jurisdiction where the actions to be performed by it hereunder makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on Seller's ability to perform such actions under this Agreement.

(b) Seller has all requisite limited liability company power and authority to execute and deliver this Agreement and any related agreements to which it is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Seller of this Agreement and the related agreements to which Seller is a party, and the performance by Seller of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary limited liability company action. This Agreement and each related agreement to which Seller is a party has been duly and validly executed and delivered by Seller and constitutes the legal, valid and binding obligation of Seller enforceable against Seller in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, arrangement, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

(c) The execution and delivery by Seller of this Agreement and the related agreements to which Seller is a party do not and will not, and the performance by Seller of its obligations under this Agreement and the related agreements to which Seller is a party does not and will not:

(i) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the organizational documents of Seller;

(ii) subject to the satisfaction of the Seller Conditions Precedent set forth in Section 2.4, be in violation of or result in a breach of or default (or give rise to any right of termination, cancellation or acceleration) under (with or without the giving of notice, the lapse of time, or both) any material contract or Permit to which Seller is a party, except for any such violations or defaults (or rights of termination, cancellation or acceleration) that would not, in the aggregate, reasonably be expected to result in a material adverse effect on Seller's ability to perform its obligations hereunder; and

(iii) subject to the satisfaction of the Seller Conditions Precedent set forth in Section 2.4, and assuming any other notifications provided in the ordinary course of business have been made, obtained or given, (i) conflict with, violate or breach any term or provision of any applicable Law, except as would not reasonably be expected to result in a material adverse effect on such Seller's ability to perform its obligations hereunder or (ii) require any consent or approval of any Governmental Authority, or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law, other than such consents, approvals, notices, declarations, filings or registrations that, if not made or obtained, would not reasonably be expected to result in a material adverse effect on Seller's ability to perform its obligations hereunder.

(d) Seller has not been served with notice of any Claim, no Claim is pending, and, to Seller's knowledge no Claim is threatened against Seller, which seeks an Order restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated by this Agreement.

(e) Seller is not in violation of, or in default under, any applicable Law or Order, the effect of which, in the aggregate, would reasonably be expected to hinder, prevent or delay Seller from performing its obligations under this Agreement.

11.2 Representations of Buyer.

(a) Buyer is a State institution of higher education, validly existing and in good standing under the Laws of its jurisdiction of formation. Buyer is duly qualified or licensed to do business in each other jurisdiction where the actions to be performed by it hereunder makes such qualification or licensing necessary, except in those jurisdictions where the failure to be so qualified or licensed would not reasonably be expected to result in a material adverse effect on Buyer's ability to perform such actions under this Agreement.

(b) Buyer has all requisite power and authority to execute and deliver this Agreement and any related agreements to which it is a party, to perform its obligations hereunder and thereunder and to consummate the transactions contemplated hereby and thereby. The execution and delivery by Buyer of this Agreement and the related agreements to which Buyer is a party, and the performance by Buyer of its obligations hereunder and thereunder, have been duly and validly authorized by all necessary Board of Trustee action. This Agreement and each related agreement to which Buyer is a party has been duly and validly executed and delivered by Buyer and constitutes the legal, valid and binding obligation of Buyer enforceable against Buyer in accordance with its terms, except as the same may be limited by bankruptcy, insolvency, reorganization, fraudulent conveyance, arrangement, moratorium or other similar Laws relating to or affecting the rights of creditors generally, or by general equitable principles.

(c) The execution and delivery by Buyer of this Agreement and the related agreements to which Buyer is a party do not and will not, and the performance by Buyer of its obligations under this Agreement and the related agreements to which Buyer is a party does not and will not:

(i) conflict with or result in a violation or breach of any of the terms, conditions or provisions of the statutory responsibilities and obligations of Buyer;

(ii) subject to the satisfaction of the Buyer Conditions Precedent set forth in Section 2.3, be in violation of or result in a breach of or default (or give rise to any right of termination, cancellation or acceleration) under (with or without the giving of notice, the lapse of time, or both) any material contract or Permit to which Buyer is a party, except for any such violations or defaults (or rights of termination, cancellation or acceleration) that would not, in the aggregate, reasonably be expected to result in a material adverse effect on Buyer's ability to perform its obligations hereunder; and

(iii) subject to the satisfaction of the Buyer Conditions Precedent set forth in Section 2.3, and assuming any other notifications provided in the ordinary course of business have been made, obtained or given, (i) conflict with, violate or

breach any term or provision of any applicable Law, except as would not reasonably be expected to result in a material adverse effect on such Buyer's ability to perform its obligations hereunder or (ii) require any consent or approval of any Governmental Authority, or notice to, or declaration, filing or registration with, any Governmental Authority, under any applicable Law, other than such consents, approvals, notices, declarations, filings or registrations that, if not made or obtained, would not reasonably be expected to result in a material adverse effect on Buyer's ability to perform its obligations hereunder.

(d) Buyer, to the best of its knowledge, has not been served with notice of any Claim, no Claim is pending, and, to Buyer's knowledge no Claim is threatened against Buyer, which seeks an Order restraining, enjoining or otherwise prohibiting or making illegal any of the transactions contemplated by this Agreement.

(e) Buyer, to the best of its knowledge, is not in violation of, or in default under, any applicable Law or Order, the effect of which, in the aggregate, would reasonably be expected to hinder, prevent or delay Buyer from performing its obligations under this Agreement.

11.3 Buyer Disclosure Obligations with Respect to Environmental Matters. Promptly after a Party becomes aware of any Existing Environmental Conditions, any violation of any Environmental Laws arising out of the construction or operation of the Host, or any Environmental Noncompliance at the Host or on the Host Premises, and any claims or actions relating to any of the same by any Governmental Authority having jurisdiction over the Host Premises, or the existence of any past or present enforcement, legal, or regulatory action or proceeding relating to such alleged Environmental Noncompliance or alleged presence of Hazardous Materials, such Party will promptly disclose such information to the other Party.

11.4 No Other Warranties. THERE ARE NO WARRANTIES UNDER THIS AGREEMENT EXCEPT TO THE EXTENT SPECIFICALLY SET FORTH IN THIS AGREEMENT. THE PARTIES HEREBY SPECIFICALLY DISCLAIM AND EXCLUDE ANY AND ALL IMPLIED WARRANTIES, INCLUDING THE IMPLIED WARRANTIES OF MERCHANTABILITY AND OF FITNESS FOR A PARTICULAR PURPOSE. WITHOUT LIMITING THE FOREGOING, EXCEPT TO THE EXTENT OTHERWISE EXPRESSLY SET FORTH IN THIS AGREEMENT, SELLER MAKES NO OTHER WARRANTIES AS TO THE CONSTRUCTION, OPERATION OR PERFORMANCE OF THE FACILITY OR THE EQUIPMENT THEREIN, INCLUDING ITS INTERCONNECTION FACILITIES, THE CONFORMANCE TO THE APPROVED SPECIFICATIONS THEREOF OR THE SUITABILITY THEREOF FOR THEIR INTENDED PURPOSE. BUYER MAKES NO WARRANTIES AS TO THE CONSTRUCTION OF ITS INTERCONNECTION FACILITIES, THEIR CONFORMANCE TO THE APPROVED SPECIFICATIONS THEREFOR OR THEIR SUITABILITY FOR THEIR INTENDED PURPOSE. IN NO EVENT WILL EITHER PARTY'S LIABILITY WITH RESPECT TO THE FAILURE OF ANY EXPRESS WARRANTIES HEREUNDER EXCEED THE REPLACEMENT PRICE OF THE APPLICABLE EQUIPMENT OR INTERCONNECTION FACILITY.

ARTICLE 12
FORCE MAJEURE EVENT; CHANGE IN LAW

12.1 Effect of Force Majeure Event. To the extent either Party is prevented by Force Majeure Event from carrying out, in whole or part, its obligations under this Agreement and such Party (the "Claiming Party") gives notice and details of the Force Majeure Event to the other Party as soon as practicable, then the Claiming Party will be excused from the performance of its obligations under this Agreement (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure Event). The Claiming Party will give prompt notice to the other Party of the Force Majeure Event and the extent of the Claiming Party's inability to fulfill its obligations under this Agreement. If the Claiming Party provides such notice orally, the Claiming Party will promptly follow such oral notice with written notice provided in accordance with the requirements of this Agreement. The Claiming Party will use commercially reasonable efforts to (a) remove or remedy such inability to perform within a reasonable period of time, and (b) mitigate the impacts on the other Party of such inability to perform. The non-Claiming Party will not be required to perform or resume performance of its obligations to the Claiming Party corresponding to the obligations of the Claiming Party excused by Force Majeure Event.

12.2 Notice of Force Majeure Event. The Claiming Party will (a) promptly notify the other Party upon the occurrence of any Force Majeure Event, which notice will indicate the scope and cause of the Force Majeure Event and the anticipated period of impact of such Force Majeure Event, (b) promptly provide such available information about the Force Majeure Event and its impact as may be reasonably requested by the other Party and (c) provide updated information regarding such Force Majeure Event and its impact from time to time as reasonably requested or periodically (but not less than once per month) until such Force Majeure Event and its impact on the obligations of the Claiming Party cease to exist. When the Claiming Party is able to resume performance of its obligations under this Agreement, it will give the other Party written notice and the Parties will resume performance under this Agreement. Subject to Section 2.2(c)(ii) and Section 12.4, if any Force Majeure Event excuses performance of the Parties' obligations under this Agreement for a period in excess of 30 days, the Term will be extended for a period equal to the period of such excuse of performance. The Parties will amend this Agreement in writing to reflect any such extension of the Term.

12.3 Scope of Force Majeure Event.

(a) The suspension of performance by a Party due to a Force Majeure Event will be of no greater scope and no longer duration that that which is necessary. The Party claiming that a Force Majeure Event has occurred will use its commercially reasonable efforts to cure the cause(s) preventing its performance of this Agreement. When the non-performing Party is able to resume performance of its obligations under this Agreement, it will immediately give the other Party written notice to that effect and will resume performance under this Agreement as soon as practicable after such notice is delivered.

(b) The settlement of strikes, lockouts and other labor disputes will be entirely within the discretion of the affected Party and such Party will not be required to settle

such strikes, lockouts or other labor disputes by acceding to demands which such Party deems to be unreasonable in its sole and absolute discretion.

12.4 Termination for Extended Force Majeure. If a Force Majeure Event prevents the Claiming Party from performing a material obligation of such Party under this Agreement for a period of 12 consecutive months, then the other Party will have the right to terminate this Agreement by written notice to the Claiming Party, in which case this Agreement will terminate 90 days after the date of such termination notice unless, within such 90-day period, (a) full performance has resumed hereunder or the Party giving the termination notice has withdrawn such notice or (b) the Claiming Party demonstrates, to the reasonable satisfaction of the other Party, that the Claiming Party is exercising sustained and diligent efforts to overcome the effects of the Force Majeure Event and reasonably expects that the Claiming Party will be able, within a period of 6 months from the end of such 90-day period, to resume performance of the obligations affected by the Force Majeure Event. Upon the effective date of such termination, neither Party will have any further rights or obligations under this Agreement, except those rights and obligations arising before the effective date of such termination and as provided in Section 14.10. Further, neither Party will be liable to the other Party for any Termination Payment or otherwise owe to the other Party any damages of any kind for or as a result of such termination; *provided, however*, that such termination will not relieve either Party of any obligations or any liability arising under or in connection with this Agreement prior to such termination.

12.5 Change in Law.

(a) Without limiting any other provision of this Agreement, if either Party (the "Affected Party") reasonably determines that the Change in Law Costs caused by, resulting from or arising out of an Change in Law are reasonably quantifiable, and that the amount of any Change in Law Costs is reasonably likely to equal or exceed the Change in Law Threshold Amount, then, not later than 15 Business Days following any request from the Affected Party, the Parties will commence to negotiate in good faith regarding any adjustments that should be made to the amounts payable under this Agreement to compensate the Affected Party for such Change in Law Costs (including, if any Changes in Law require one-time capital improvements in connection with the Facility, the terms on which the applicable Change in Law Costs are to be amortized over the remainder of the Term). Prior to such negotiations, the Affected Party will provide the other Party with documentation reasonably evidencing the Affected Party's calculation of such Change in Law Costs, and an opportunity to discuss such documentation with the Affected Party. If the Parties, within a period of 60 days following the Affected Party's request for negotiation regarding the Change in Law Costs, reach agreement that such Change in Law Costs are reasonably likely to exceed the Change in Law Threshold Amount, and regarding any adjustments that should be made to the amounts payable under this Agreement to compensate the Affected Party for such Change in Law Costs, Seller will petition the SCPSC for approval of such adjustments to this Agreement. If the Parties do not, within a period of 60 days following the Affected Party's request for negotiation regarding the Change in Law Costs, reach agreement that such Change in Law Costs are reasonably likely to exceed the Change in Law Threshold Amount, or regarding any adjustments that should be made to the amounts payable under this Agreement to compensate the Affected Party for such

Change in Law Costs, the Affected Party will refer the matter to the South Carolina Office of Regulatory Staff (ORS) for mediation, pursuant to the statutory function of the ORS set forth in S.C. Code Ann. § 58-4-50(A)(9). If, within a period of 60 days following submission of the Affected Party's request for mediation, the Parties reach agreement that such Change in Law Costs are reasonably likely to exceed the Change in Law Threshold Amount, and regarding any adjustments that should be made to the amounts payable under this Agreement to compensate the Affected Party for such Change in Law Costs, either Seller (if only Seller is eligible) or both Parties (if both Parties are eligible) will petition the SCPSC for approval of such adjustments to this Agreement. If the Parties do not, within a period of 60 days following submission of the Affected Party's request for mediation regarding the Change in Law Costs, reach agreement that such Change in Law Costs are reasonably likely to exceed the Change in Law Threshold Amount, or regarding any adjustments that should be made to the amounts payable under this Agreement to compensate the Affected Party for such Change in Law Costs, the Affected Party will be entitled at any time thereafter, in its sole and absolute discretion, effective 365 days following notice from the Affected Party to the other Party, and without any liability whatsoever (including liability for any Termination Payment) on the part of the Affected Party to the other Party or any other Person, to terminate this Agreement, notify the SCPSC of said termination and request any State Regulatory Approvals that may be required to approve, ratify or confirm such termination.

(b) The Change in Law Threshold Amount will constitute a threshold to any sharing by the non-Affected Party in Change in Law Costs, but will not constitute a deductible amount unless otherwise agreed by the Parties. Once the aggregate Change in Law Costs have equaled or exceeded the Change Event Threshold Amount, the non-Affected Party will, subject to satisfaction of the requirements of Section 12.5(a), be responsible for the non-Affected Party's agreed share of any and all Change in Law Costs (unless otherwise agreed by the Parties).

(c) If, following the Effective Date, applicable Law imposes any enforceable and unappealable limits or other enforceable and unappealable compliance obligations related to emissions produced from the combustion of fuel by the Facility, and such limits or obligations are reasonably likely to have a substantial and materially adverse impact on the economics of this Agreement to Seller or Seller's rights and obligations under this Agreement, then the following will apply:

(i) Upon the occurrence of any event described in Section 12.5(c) above, Seller will promptly transmit to Buyer a copy or notice thereof, as appropriate, and will, within 10 days after delivery of such notice, give to Buyer an explanation in reasonable detail indicating why the terms and conditions of such limits or obligations are reasonably likely to have a material adverse effect on the economics of this Agreement to Seller or Seller's rights and obligations under this Agreement, including an analysis in appropriate detail showing the economic impact of such limits or obligations upon Seller;

(ii) If Buyer so chooses, Buyer and Seller will meet and negotiate in good faith to determine if appropriate alterations to this Agreement or other arrangements can be agreed to that will address the operational or economic issues caused by such limits or obligations; and

(iii) If the Parties are unable or unwilling to reach agreement pursuant to Section 12.5(c)(ii), Seller will have the right to terminate this Agreement, without liability or any further obligations to Buyer, upon 365 days prior written notice to Buyer and may notify the SCPSC of said termination and request any State Regulatory Approvals that may be required to approve, ratify or confirm such termination.

ARTICLE 13
INSURANCE

13.1 Required Insurance.

(a) Seller will maintain during the term of this Agreement, and will require any general contractor of Seller retained to perform significant construction or demolition work at the Facility or on the Site to maintain during the term of such work, the insurance coverage set forth below with insurance companies having an A.M. Best credit rating of "A-, VII" or better, with minimum coverage limits indicated below on policies issued on an "occurrence" basis, and naming Buyer and Seller, and their respective officers, directors, shareholders, agents, independent contractors and Affiliates as additional insureds for ongoing and completed operations on all policies except workers compensation and employers liability:

(i) Umbrella insurance coverage in the amount of $5,000,000 and excess or umbrella liability insurance coverage with a limit of not less than $5,000,000 per occurrence and per project. These limits will apply in excess of each of the below mentioned policies;

(ii) Workers' compensation insurance (or qualification as a self-insurer) covering its employees in amounts at least equal to the minimum coverage amounts provided under the laws of South Carolina, notwithstanding any provision limiting requirements to a particular number of employees. Seller will provide for, or require any Subcontractor (as defined below) to maintain, similar coverage for the Subcontractor's employees employed in connection with this Agreement;

(iii) Employers' liability insurance that covers both "bodily injury by accident" and "bodily injury by disease" with limits of not less than $1,000,000 each accident/$1,000,000 disease policy limit/$1,000,000 each employee;

(iv) Commercial general liability insurance that covers bodily injury, personal injury, and property damage, including products liability and contractual liability coverage, with per occurrence limits of not less than $1,000,000 and an aggregate limit of not less than $2,000,000 and (x) which will include

"contractual" coverage for the indemnity clause set forth in Article 16 below and Article 12 of the Lease and (y) with coverage written on a primary and non-contributory basis;

(v) Automobile liability insurance coverage (including coverage for claims against Buyer for injuries to employees of Seller or any of its Subcontractors) for owned, non-owned, and hired autos with a limit of not less than $1,000,000 per accident;

(vi) Commercial property insurance insuring all improvements, fixtures and personal property located on the Site from time to time in an amount equal to 100% of the full replacement cost thereof, subject to a deductible reasonably acceptable to Buyer; said commercial property insurance policy will insure against the perils of fire and extended coverage and will include "special form" property insurance for physical loss or damage including, without duplication of coverage, theft, vandalism and malicious mischief; and

(vii) During any period within which any construction or installation of any improvements, fixtures or personal property at the Site is taking place, "special form" builder's risk insurance upon such improvements, fixtures or personal property to the full replacement value thereof. Said builder's risk insurance policy will insure against the perils of fire and extended coverage and will include "special form" builder's risk insurance for physical loss or damage including, without duplication of coverage, theft, vandalism and malicious mischief.

(b) Seller agrees to make Buyer an additional insured on Seller's commercial general liability and automobile liability policies, and will provide Buyer with copies of policy endorsements reflecting Buyer's status as an additional insured thereunder. Insurance coverage provided by Seller under this section will not include any of the following: (i) any claims made insurance policies; (ii) any self-insured retention or deductible amount greater than $250,000.00, unless approved in writing by Buyer; (iii) any endorsement limiting coverage available to Buyer which is otherwise required by this section; and (iv) any policy or endorsement language that (A) limits the duty to defend Buyer under the policy or (B) provides coverage to Buyer only if Seller is negligent.

(c) Notwithstanding the minimum limits of coverage set forth above, Seller will name Buyer, its officers, directors, employees, subsidiaries, successors, and assigns as additional insureds for the full limits of insurance coverage purchased by Seller. The additional insured coverage provided pursuant to this Section 13.1(c) will provide coverage to Buyer for all claims, losses, demands, liens, causes of action or suits, judgments, fines, assessments, liabilities, damages and injuries (including death) covered by Article 16. Seller is responsible for payment of all deductibles, self-insured retentions or similar charges for the additional insured coverage required pursuant to this Section 13.1(c).

(d) Prior to commencing operations hereunder, and thereafter upon Buyer's reasonable request, Seller will provide to Buyer a certificate of insurance evidencing Seller's compliance with the requirements of this Section 13.1, bearing applicable endorsements and specifically stating that such insurance will provide prior notice to Buyer in the event of cancellation or any material change of such insurance policies. Seller also agrees to provide Buyer with a copy of any such notice it receives from its insurance company promptly after receiving such notice. Seller hereby agrees that if it fails to furnish the policy endorsements or the certificates of insurance required hereunder, or if Buyer receives notice that any policy of insurance issued to Seller has been canceled or no longer meets the requirements of this Section 13.1, then Buyer (i) may suspend this Agreement until insurance is obtained; (ii) may terminate this Agreement immediately for cause; or (iii) may, but will have no obligation to, obtain forced placement insurance that meets the requirements of this Section 13.1 at Seller's sole cost from any broker or insurer satisfactory to Buyer.

13.2 Right to Self-Insure. Notwithstanding anything herein to the contrary, and except as provided in this Section 13.2, Seller will have the right to self-insure as to any insurance required under this Agreement, *provided* that with respect to any self-insurance by Seller:

(a) such self-insurance by Seller is permitted by all Laws and Orders affecting the Site and the Facility or otherwise applicable to Seller;

(b) Seller will maintain a tangible net worth of at least $500,000,000;

(c) such self-insurance program will be reasonably acceptable to Buyer;

(d) Seller will maintain loss histories and will establish and maintain reserves adequate to cover losses projected by such loss histories;

(e) Seller will protect Buyer to the same extent as it would if it had the commercial general liability policy required hereunder;

(f) Seller will provide annually to Buyer and Buyer's mortgagee a certificate indicating its decision to self-insure, which certificate will certify that Seller's net worth is not less than $500,000,000. In addition, simultaneously with the delivery of said notice, Seller will deliver to Buyer and Buyer's mortgagee, if any, unaudited financial statements of Seller for Seller's most recent fiscal year, which financial statements will be prepared in accordance with GAAP and certified as true and correct by an officer of Seller; and

(g) Seller will continue to maintain such self-insurance after the expiration or termination of this Agreement for a period of not less than 3 years. The minimum amounts of insurance coverage required hereunder will not be construed to create a limit on Seller's liability with respect to its indemnification obligations hereunder.

The foregoing right of Seller to self-insure will not apply with respect to insurance coverage related to accidental death and dismemberment, which policy will at all times be maintained with

a third party provider and will consist of coverage that is consistent with the requirements set forth in Section 13.1(a)(iv).

13.3 Subcontractors.

(a) Seller may hire or engage one or more subcontractors or other third parties (each, a "Subcontractor") to perform a portion of its obligations under this Agreement; *provided*, that: Seller will ensure that each Subcontractor's employees have received appropriate training to handle the tasks proposed to be undertaken by such employees at the Site, and have received instruction with respect to the security and safety precautions to be observed and taken at the Site;

(b) Seller will remain responsible for the acts and omissions of each Subcontractor as if those acts or omissions were Seller's own acts and omissions, including each Subcontractor's compliance with the terms and conditions of this Agreement; and

(c) Seller will ensure that each Subcontractor maintains the following types of insurance in at least the following amounts:

(i) Workers' compensation insurance satisfying applicable statutory limits;

(ii) Employer's liability insurance with the following minimum limits: $1,000,000 each accident for bodily injury by accident, $1,000,000 each employee for bodily injury by disease, and $1,000,000 aggregate policy limit for bodily injury by disease;

(iii) Commercial general liability insurance with the following minimum limits: $2,000,000 general aggregate per project, $2,000,000 premises, products and completed operations aggregate, $2,000,000 bodily injury/property damage per occurrence, and $2,000,000 personal injury and advertising injury limit, with products completed operations coverage provided for not less than 3 years from the date of final completion of the applicable project; and

(iv) Automobile liability covering any Seller auto (including owned, non-owned and hired autos), with minimum required limits of $1,000,000 combined single limit each accident.

13.4 Right to Cure. If a Party fails to procure or maintain any insurance required pursuant to Section 13.1, the other Party will have the right, but not the obligation, upon not less than 30 days prior written notice from such other Party to the non-performing Party, to procure such insurance on behalf of the non-performing Party and in any such event such other Party will be entitled to recover the premiums paid for such insurance as an amount due under this Agreement.

ARTICLE 14
DEFAULT AND TERMINATION

14.1 Events of Default. The occurrence at any time with respect to a Party of any of the following events constitutes an event of default (an "Event of Default") with respect to such Party (the "Defaulting Party"):

(a) The failure to make, when due, any payment required pursuant to this Agreement, if such failure is not remedied within 10 days after written notice;

(b) Any representation or warranty made by such Party in this Agreement is false or misleading in any material respect when made or when deemed made or repeated which is not remedied within 10 days after written notice;

(c) The failure to perform any material covenant or obligation set forth in this Agreement (other than to the extent constituting a separate Event of Default), if such failure is not remedied within 30 days after written notice or, if such performance cannot reasonably be completed within said 30-day period, failure to commence the performance within such 30-day period and to pursue the same diligently to completion;

(d) Such Party becomes Bankrupt;

(e) A Party's actual fraud or willful misconduct in connection with this Agreement;

(f) A Party assigns this Agreement or any of its rights in this Agreement, except as may be permitted under Section 18.1; and

(g) A Merger Event occurs with respect to such Party.

14.2 Remedies for Event of Default. If an Event of Default will occur and is continuing, the Non-Defaulting Party will have the right (but not the obligation) to pursue any or all of the following remedies:

(a) Suspend performance of the Non-Defaulting Party's obligations under this Agreement;

(b) Subject to the express limitations on remedies set forth in this Agreement, including the provisions of Section 14.7, receive from the Defaulting Party actual and direct damages incurred by the Non-Defaulting Party as a result of or in connection with such Event of Default (including during any applicable cure period, whether or not the Non-Defaulting Party has elected to suspend performance during such cure period); and

(c) Exercise all other remedies available to the Non-Defaulting Party at law or in equity.

14.3 Termination for an Event of Default. If an Event of Default has occurred and is not cured within the applicable cure period, if any, set forth in Section 14.1, the Non-Defaulting

Party will have the right, at any time when such Event of Default is continuing, and in addition to the remedies set forth in Section 14.2, to:

(a) designate by notice to the Defaulting Party a day, no earlier than the day such notice becomes effective and no later than 20 days after the day such notice becomes effective, on which this Agreement will terminate (the "Early Termination Date");

(b) recover in connection with such termination an amount calculated in accordance with Section 14.5, and

(c) subject to the express limitations on remedies set forth in this Agreement, including the provisions of Section 14.7, pursue any other right or remedy available under this Agreement or applicable Law. If notice of termination has not been received by the date that is 30 days following the last day of any applicable cure period, the Event of Default is waived by the Non-Defaulting Party and no further damages will accrue with respect to such Event of Default.

14.4 Effect of Designation. If notice designating an Early Termination Date is given under Section 14.3, the Early Termination Date will occur on the date so designated, whether or not the relevant Event of Default or Termination Event is then continuing. Upon the occurrence or effective designation of an Early Termination Date, no further payments or deliveries under this Agreement will be required to be made, but without prejudice to the other provisions of this Agreement. The amount, if any, payable in respect of an Early Termination Date will be determined pursuant to Section 14.5.

14.5 Termination Payment. On or as soon as reasonably practicable following the occurrence of an Early Termination Date, the Non-Defaulting Party will determine the Termination Payment, plus (ii) any costs incurred by the Non-Defaulting Party as a result of the termination of this Agreement due to the Defaulting Party's default, plus (iii) any unpaid amounts owing under this Agreement from the Defaulting Party to the Non-Defaulting Party that arose before the Early Termination Date, minus (iv) any unpaid amounts owing under this Agreement from the Non-Defaulting Party to the Defaulting Party, minus (v) any amounts that the Non-Defaulting Party is able to recover pursuant to mitigation under Section 14.9. If the resulting amount is a positive amount, the Defaulting Party will pay such amount to the Non-Defaulting Party. If the resulting amount is a negative amount, such amount will be deemed to be zero and no payment will be made to either Party.

14.6 Additional Rights.

(a) Payment or performance by the Non-Defaulting Party of any of the Defaulting Party's obligations will not waive or cure any breach occasioned by the Defaulting Party's failure or refusal to pay or perform same. Any sums expended by the Non-Defaulting Party in curing any defaults will be repaid by the Defaulting Party to the Non-Defaulting Party within 10 days after demand. Any such sums that are not paid within such 10-day period will bear interest at the Interest Rate.

(b) If either Party is at any time during the Term in default of any of such Party's obligations under the Ground Lease, the other Party will be entitled to suspend performance of any or all of its obligations under this Agreement until such time as the defaulting Party has cured such defaults.

14.7 Remedies Cumulative. The amount determined in accordance with Section 14.5 will be the Parties' sole and exclusive remedy under this Agreement or otherwise for termination for an Event of Default. Subject to the express limitations set forth in the foregoing sentence, each right or remedy of the Parties provided for in this Agreement will be cumulative of and will be in addition to every other right or remedy provided for in this Agreement. A Party's exercise of any one or more of the rights or remedies provided for in this Agreement will not preclude the simultaneous or later exercise by such Party of any or all other rights or remedies provided for in this Agreement.

14.8 Closeout Setoffs. The Non-Defaulting Party will be entitled, at its option and in its discretion, to set off, against any amounts due and owing from the Non-Defaulting Party to the Defaulting Party under this Agreement, any amounts due and owing from the Defaulting Party to the Non-Defaulting Party under this Agreement or any other agreements, instruments or undertakings between the Defaulting Party and the Non-Defaulting Party. The remedy provided for in this section will be without prejudice and in addition to any right of setoff, combination of accounts, lien or other right to which any Party is at any time otherwise entitled (whether by operation of Law, contract or otherwise).

14.9 Duty to Mitigate. Each Party agrees that it has a duty to mitigate damages, and that it will use commercially reasonable efforts to minimize any damages it may incur as a result of the other Party's performance or non-performance of this Agreement, *provided* that in no event will such mitigation obligations include any requirement that either Party pay any amounts to the other Party. The Parties will exercise commercially reasonable efforts when purchasing or selling, as the case may be, electrical energy or environmental attributes in order to mitigate damages.

14.10 Survival. Notwithstanding any provisions herein to the contrary, any provision hereof which by its terms applies to the period after termination of this Agreement and any provisions hereof necessary to give effect to the intent of the Parties hereunder after the termination or expiration of this Agreement will survive in full force the termination or expiration of this Agreement, including the obligations set forth in Section 2.2, Section 2.3, Section 4.3, Section 4.4, Section 4.5, Article 10, Article 13, Section 14.2, Section 14.3, Section 14.7, Section 14.9, this Section 14.10, Article 15, Article 16 and Article 18 (other than Section 18.1).

ARTICLE 15
TERMINATION FOR CONVENIENCE

15.1 Termination for Convenience. Notwithstanding any other provision of this Agreement, Buyer shall have the right at any time after the commencement of the eleventh (11^{th}) Contract Year to terminate this Agreement by providing notice of termination to Seller, such termination to be effective not less than 180 days after such notice is provided to Seller, and

paying any Termination Payment applicable to the Contract Year in which such termination occurs. See Exhibit D. If in connection with any such termination, Buyer as Landlord under the Ground Lease is no longer able to provide the Utilities, then, prior to any termination of this Agreement under this Section 15.1, Buyer will provide Seller with access and rights of entry for Seller to provide the Utilities for itself, at Seller's sole cost and expense, from the existing facilities at the Host or otherwise. If Buyer terminates this Agreement pursuant to this Section 15.1 and makes any applicable Termination Payment on or before the effective date of such termination, Buyer will not be considered in default of this Agreement or have any other liability to Seller on account of such termination and Seller will have no rights or remedies against Buyer except as expressly provided in this Section 15.1.

15.2 Effect of Termination. Except as provided in Section 14.10, upon a termination of this Agreement pursuant to this Article 15, the Parties will be relieved of all of their respective obligations under this Agreement arising from and after the effective date of such termination; *provided, however*, that such termination will not relieve either Party of any obligations or any liability arising under or in connection with this Agreement prior to such termination.

ARTICLE 16
INDEMNIFICATION; LIMITATION OF LIABILITY

16.1 Seller Indemnification. Seller (the "Indemnifying Party") agrees to indemnify, defend and hold harmless Buyer (the "Indemnified Party") from and against all claims, demands, damages, losses, liabilities, fines, penalties, judgments, amounts paid in settlement, deficiencies, charges, Taxes, obligations, demands, fees, interest, costs, and expenses (including attorneys' and other professionals' fees) ("Losses") to the extent caused by, resulting from, or arising out of any breach or violation of this Agreement by the Indemnifying Party, any Event of Default with respect to the Indemnifying Party under this Agreement, or any negligence or intentional misconduct by or of the Indemnifying Party, its Affiliates, its directors, officers, employees, or agents. Nothing in this Section 16.1 will affect any liability of either Party to the other for any breach of this Agreement or for any event or occurrence for which any specific remedy is provided hereunder. The indemnification obligations under this Agreement will not be construed to relieve any insurer of its obligation to pay claims consistent with the provisions of any insurance policy.

16.2 Notice of Claims; Procedure. The Indemnified Party will, with reasonable promptness after obtaining knowledge of a third party claim, provide the Indemnifying Party with written notice of the proceedings, claims, demands or assessments that may be subject to indemnification; *provided, however*, that failure to give prompt notice will not adversely affect any claim for indemnification hereunder except to the extent the Indemnifying Party's ability to contest any claim by any third party is materially adversely affected as a result thereof. The notice will include (i) a statement of the basis of the claim for indemnification, including a summary of the facts or circumstances that form the basis for the claim, (ii) a good faith estimate of the amount of Losses, and (iii) copies of any pleadings or demands from the third party. The Indemnifying Party will have 30 days after its receipt of the claim notice to notify the Indemnified Party in writing whether or not the Indemnifying Party agrees that the claim is subject to this Article 16 and, if so, whether the Indemnifying Party elects to undertake, conduct and control, through counsel of its choosing and at its sole risk and expense, the settlement or

defense of the claim. If within 30 days after its receipt of the claim notice, the Indemnifying Party notifies the Indemnified Party that it elects to undertake the settlement or defense of the claim, the Indemnified Party will cooperate with the Indemnifying Party in connection with the settlement or defense of the claim, including by making available to the Indemnifying Party all relevant information and the testimony of employees and agents material to the defense of the claim. The Indemnifying Party will reimburse the Indemnified Party for reasonable out-of-pocket costs incurred in connection with such cooperation. If the Indemnifying Party exercises its right to undertake the settlement or defense of the claim in accordance with the provisions of this Section 16.2 and the Indemnified Party notifies the Indemnifying Party that the Indemnified Party desires to retain separate counsel in order to participate in or proceed independently with such contest, defense or litigation, the Indemnified Party may do so at its own expense. The Indemnified Party will have the right to pay or settle any claim at any time without the consent of the Indemnifying Party; *provided, however*, that if the Indemnifying Party is contesting the claim in good faith and with diligence and the Indemnified Party pays or settles the claim without the Indemnifying Party's consent, the Indemnified Party will be deemed to have waived any right to indemnification with respect to such claim. If the Indemnifying Party does not provide a responsive notice within the 30-day period set forth in this Section 16.2, the Indemnified Party will have the right to contest, settle or compromise the claim at its exclusive discretion, at the Indemnifying Party's sole cost and expense, and the Indemnifying Party will be deemed to have waived any claim, defense or argument that the Indemnified Party's settlement or defense of such claim is in any respect inadequate or unreasonable.

16.3 Survival; Limitations. The indemnity obligations and rights of the Parties set forth in this Article 16 will survive the termination of this Agreement for 2 years after expiration or termination for any reason of this Agreement.

16.4 Insurance Proceeds. If the Indemnifying Party is obligated to indemnify the Indemnified Party under this Article 16, the amount payable to the Indemnified Party will be the amount of the Indemnified Party's Losses net of any insurance proceeds received by the Indemnified Party following a reasonable effort by the Indemnified Party to obtain such insurance proceeds.

16.5 Limitation of Liability. **THE PARTIES CONFIRM THAT THE EXPRESS REMEDIES AND MEASURES OF DAMAGES PROVIDED IN THIS AGREEMENT SATISFY THE ESSENTIAL PURPOSES HEREOF. FOR BREACH OF ANY PROVISION FOR WHICH AN EXPRESS REMEDY OR MEASURE OF DAMAGES IS PROVIDED, SUCH EXPRESS REMEDY OR MEASURE OF DAMAGES WILL BE THE SOLE AND EXCLUSIVE REMEDY, THE OBLIGOR'S LIABILITY WILL BE LIMITED AS SET FORTH IN SUCH PROVISION AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. IF NO REMEDY OR MEASURE OF DAMAGES IS EXPRESSLY PROVIDED HEREIN, THE OBLIGOR'S LIABILITY WILL BE LIMITED TO DIRECT ACTUAL DAMAGES ONLY, SUCH DIRECT ACTUAL DAMAGES WILL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. WITHOUT PREJUDICE TO THE CALCULATION OF ANY TERMINATION PAYMENT AMOUNT, NEITHER PARTY WILL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, INCLUDING**

INDIRECT DAMAGES IN THE NATURE OF LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE; *PROVIDED, HOWEVER*, THAT NOTWITHSTANDING THE FOREGOING, IN NO EVENT WILL THE FOREGOING LIMITATIONS OF LIABILITY BE APPLIED TO LIMIT THE EXTENT OF THE LIABILITY OF EITHER PARTY TO THE OTHER FOR OR WITH RESPECT TO ANY INDEMNITY OR OTHER THIRD PARTY CLAIMS OR FOR OR WITH RESPECT TO ANY BREACH OF THE CONFIDENTIALITY PROVISIONS OF THIS AGREEMENT. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE. TO THE EXTENT ANY DAMAGES REQUIRED TO BE PAID HEREUNDER ARE LIQUIDATED, THE PARTIES ACKNOWLEDGE THAT THE DAMAGES ARE DIFFICULT OR IMPOSSIBLE TO DETERMINE, OR OTHERWISE OBTAINING AN ADEQUATE REMEDY IS INCONVENIENT AND THE DAMAGES CALCULATED HEREUNDER CONSTITUTE A REASONABLE APPROXIMATION OF THE HARM OR LOSS. NOTHING IN THE FOREGOING WILL BE CONSTRUED TO LIMIT ANY LEGAL, EQUITABLE OR STATUTORY RIGHTS OF SETOFF OR ANY RIGHTS UNDER ANY PERFORMANCE ASSURANCE, OR TO PROHIBIT ANY ACTION TO ENFORCE ANY REMEDY PROVIDED UNDER THIS AGREEMENT.

ARTICLE 17
CONFIDENTIALITY

17.1 Confidential Information. The term "Confidential Information" as used in this Agreement means:

(a) information provided by or on behalf of one Party (the "Disclosing Party") to the other Party (the "Receiving Party") or its Representatives in connection with this Agreement, whether transmitted or disclosed to the Receiving Party or its Representatives in person, electronically, by telephone or facsimile transmission, in writing, by drawings, orally, or in any other manner or form, that is clearly labeled or designated by the Disclosing Party as "confidential" or "proprietary" or, if disclosed orally, clearly identified as confidential with that status confirmed promptly thereafter in writing, identifying the substance and content of such information;

(b) any notes, analysis, compilations, studies, interpretations, memoranda, or other documents and writings prepared by the Receiving Party or its Representatives that contain, reflect, or are based upon, in whole or in part, any information described in clause (a) above and marked as "confidential" or "proprietary";

provided, however, that Confidential Information will not include:

(i) information already lawfully in the Receiving Party's possession at the time of its receipt from the Disclosing Party;

(ii) information that is lawfully obtained by the Receiving Party from a third party subsequent to its receipt from the Disclosing Party, if the third party is free from any obligation of confidentiality to the Disclosing Party or its Affiliates with respect to such information;

(iii) information that (A) at the time of disclosure by the Disclosing Party to the Receiving Party, is available to the public, or (B) after disclosure by the Disclosing Party to the Receiving Party, becomes available to the public, except where such availability arises out of the breach of this Agreement by the Receiving Party;

(iv) information independently developed by the Receiving Party without violating its obligations under this Agreement; and

(v) information that the Disclosing Party, in writing, specifically authorizes the Receiving Party to disclose prior to such disclosure.

17.2 Disclosure and Use of Confidential Information. The Receiving Party:

(a) will hold in strict confidence all Confidential Information and, without the prior written consent of the Disclosing Party, will not disclose any Confidential Information to any Person (other than the Receiving Party's Representatives), using at a minimum the same degree of care to avoid disclosure of such Confidential Information as the Receiving Party uses with respect to its own confidential information, but in any event not less than a reasonable degree of care;

(b) will use the Confidential Information solely in connection with this Agreement; and

(c) will not disclose any Confidential Information to the Receiving Party's Representatives unless such individuals have a need to know such Confidential Information for a purpose specifically allowed under this Agreement, and have been informed of this Agreement and the terms hereof, *provided* that the Receiving Party will be liable for any breach of the confidentiality provisions of this Agreement by its Affiliates or Representatives.

17.3 Required Disclosure. The confidentiality requirements of this Agreement will not apply to Confidential Information to the extent that the Receiving Party is required to disclose such Confidential Information pursuant to applicable Law or legal process, including the South Carolina Freedom of Information Act. If the Receiving Party is compelled by any such Law or legal process to disclose any Confidential Information, the Receiving Party, to the extent not prohibited by applicable Law, will provide the Disclosing Party with prompt notice of such requirement, and will reasonably cooperate with the Disclosing Party in obtaining appropriate protective order(s) for such compelled disclosure (in each case at the Disclosing Party's expense). If the Receiving Party is ordered or instructed to disclose Confidential Information by a court of competent jurisdiction or, in the professional judgment of the Receiving Party's counsel, the Receiving Party is compelled to permit such disclosure or else risk civil or criminal liability, or if the Disclosing Party waives compliance with the confidentiality provisions of this

Agreement, then the Receiving Party may so disclose such Confidential Information or other information without liability hereunder, *provided* that to the extent not prohibited by applicable law, the Receiving Party has given the Disclosing Party a reasonable opportunity under the circumstances to review the text of such disclosure before it is made.

17.4 Specific Performance; Injunctive Relief. The Receiving Party acknowledges and agrees that, because of the sensitive and confidential nature of the Confidential Information, the breach by the Receiving Party of the terms of this Agreement with regard to disclosure of Confidential Information may cause the Disclosing Party irreparable harm and damage and that a monetary remedy for any such breach will be inadequate and will be impracticable and extremely difficult to prove. Therefore, the Receiving Party agrees that, in the event of such breach, the Disclosing Party will have the right to exercise all remedies available at law and equity, including specific performance and temporary and permanent injunctive relief, including temporary restraining orders, preliminary injunctions and permanent injunctions, without the necessity of posting a bond or making any undertaking in connection therewith and without the necessity of proving actual damages. Any such requirement of a bond or undertaking is hereby waived by the Receiving Party, and the Receiving Party acknowledges that in the absence of such a waiver, a bond or undertaking might be required by the court. The Receiving Party hereby submits to the subject matter jurisdiction of any South Carolina court granting such relief.

17.5 Survival of Obligations. The confidentiality obligations of the Receiving Party under this Agreement will remain in full force and effect for a period of 2 years from the date of termination of this Agreement, except for obligations related to trade secrets of a Party, which obligation shall extend indefinitely.

17.6 Public Announcements. Neither Party may issue or make any public announcement, press release or statement regarding this Agreement unless the public announcement, press release or statement is issued jointly by the Parties or, before the release of the public announcement, press release or statement, the Party furnishes the other Party with a copy of such announcement, press release or statement, and obtains the approval of the other Party, such approval not to be unreasonably withheld, conditioned or delayed. However, no Party will be prohibited from issuing or making any such public announcement, press release or statement, without obtaining approval from the other Party, if it is necessary to do so to comply with applicable Laws, legal proceedings or rules and regulations of any stock exchange having jurisdiction over such Party or if it is necessary to do so in connection with such Party or its Affiliates' financial statements

ARTICLE 18
MISCELLANEOUS

18.1 Assignment.

(a) Except as provided in Section 18.1(b) below, any sale, transfer, or assignment of this Agreement or any interest in the Facility or the Host will be null and void and a breach of this Agreement without the prior written consent of the other Party, which consent will not be unreasonably withheld, conditioned or delayed so long as (i) the assignee expressly assumes the transferring Party's payment and performance

obligations under this Agreement, and (ii) the transferring Party delivers evidence satisfactory to the non-transferring Party of the proposed assignee's technical and financial capability to fulfill the assigning Party's obligations hereunder.

(b) Either Party may sell, transfer or assign this Agreement or its interests in the Facility on notice to the other Party but without the other Party's consent if such sale, transfer or assignment is in connection with a Permitted Transaction *provided* that, in the event the Permitted Transaction involves a transfer by Buyer to an Affiliate, Buyer remains secondarily responsible for fulfilling such Affiliate's obligations hereunder unless Buyer demonstrates to Seller's reasonable satisfaction that the Affiliate has the financial capability to fulfill Buyer's obligations hereunder.

(c) This Agreement will be binding on and inure to the benefit of the Parties and their permitted successors and assigns.

18.2 Relationship of the Parties.

(a) Seller is an independent contractor and nothing contained herein will be construed as constituting any relationship with Buyer other than that of purchaser and independent contractor, nor will it be construed as creating any relationship whatsoever between the Parties, including employer/employee, partners or joint venture parties.

(b) Each Party is acting for its own account, and it has made its own independent decisions to enter into this Agreement and as to whether this Agreement is appropriate or proper for it based upon its own judgment and upon advice from such advisers as it has deemed necessary. It is not relying on any communication (written or oral) of the other Party as investment advice or as a recommendation to enter into this Agreement; it being understood that information and explanations related to the terms and conditions of this Agreement will not be considered investment advice or a recommendation to enter into this Agreement. No communication (written or oral) received from the other Party will be deemed to be an assurance or guarantee as to the expected results of this Agreement except as otherwise expressly set forth herein.

(c) Each Party is capable of assessing the merits of and understanding (on its own behalf or through independent professional advice), and understands and accepts, the terms, conditions and risks of this Agreement. It is also capable of assuming, and assumes, the risks of this Agreement.

(d) Neither Party is acting as a fiduciary for or an adviser to the other Party in respect of this Agreement.

(e) Each Party is entering into this Agreement and any other documentation relating to this Agreement as principal (and not as agent or in any other capacity, fiduciary to otherwise).

18.3 Notices. All notices, requests, statements or payments will be made to the addresses and persons specified in Exhibit F. All notices, requests, statements or payments will be made in writing except where this Agreement expressly provides that notice may be made

orally. Notices required to be in writing will be delivered by hand delivery, overnight delivery, facsimile, or e-mail (so long as a copy of such e-mail notice is provided immediately thereafter by hand delivery, overnight delivery, or facsimile). Notice by facsimile will (where confirmation of successful transmission is received) be deemed to have been received on the day on which it was transmitted (unless transmitted after 5:00 p.m. at the place of receipt or on a day that is not a Local Business Day, in which case it will be deemed received on the next Local Business Day). Notice by hand delivery or overnight delivery will be deemed to have been received when delivered. Notice by e-mail will be deemed to have been received when such e-mail is transmitted, so long as a copy of such e-mail notice is delivered immediately thereafter by hand delivery, overnight delivery, or facsimile; *provided* that no such copy of e-mail notices will be required for notifications sent in the ordinary course of business by e-mail and notifications of changes in availability of the Facility sent by e-mail. When notice is permitted to be provided orally, notice by telephone will be permitted and will be deemed to have been received at the time the call is received. A Party may change its address by providing notice of the same in accordance with the provisions of this Section 18.3.

18.4 Resolution of Disputes.

(a) If any dispute (including payment dispute), controversy or claim arising out of or relating to this Agreement or the breach, termination or validity thereof should arise between the Parties (a "Dispute"), the Party wishing to declare a Dispute will deliver to the other Party a written notice identifying the disputed issue.

(b) Following delivery and receipt of a notice of Dispute, executives of both Parties will meet at a mutually acceptable time and place within 10 Business Days after receipt of such notice and thereafter as often as they reasonably deem necessary, to exchange relevant information and to attempt to resolve the Dispute; *provided, however*, in the event of a threatened, actual or claimed breach of the confidentiality provisions of this Agreement, the Disclosing Party may bypass the provisions of this Dispute discussion provision and immediately seek relief in a court of competent jurisdiction to stay any threatened or continued breach of this Agreement. In such meetings and exchanges, a Party will have the right to designate as confidential any information that such Party offers. If the matter has not been resolved in the aforementioned manner within 30 days after delivery of the notice of the Dispute by a Party, or if the Parties fail to meet within 10 Business Days as required above, either Party may initiate any legal action, suit or other proceeding available to it to resolve such Dispute.

18.5 Governing Law; Venue; Waiver of Jury Trial.

(a) This Agreement and the rights and duties of the Parties hereunder will be governed by and construed, enforced and performed in accordance with the laws of the State of South Carolina, without regard to principles of conflicts of law that would result in the application of the law of any other state.

(b) EACH PARTY IRREVOCABLY AND UNCONDITIONALLY SUBMITS TO THE EXCLUSIVE JURISDICTION OF THE GENERAL COURTS OF JUSTICE OF THE STATE OF SOUTH CAROLINA AND TO THE EXCLUSIVE

JURISDICTION OF THE UNITED STATES DISTRICT COURT FOR THE DISTRICT OF SOUTH CAROLINA, AND ANY APPELLATE COURTS FROM ANY SUCH COURT, IN ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT OR THE SUBJECT MATTER HEREOF OR FOR RECOGNITION OR ENFORCEMENT OF ANY JUDGMENT, AND EACH OF THE PARTIES IRREVOCABLY AND UNCONDITIONALLY AGREES THAT ALL CLAIMS IN RESPECT OF ANY SUCH ACTION OR PROCEEDING SHALL BE HEARD AND DETERMINED IN SUCH COURTS. EACH OF THE PARTIES AGREES THAT A FINAL JUDGMENT IN ANY SUCH ACTION OR PROCEEDING SHALL BE CONCLUSIVE AND MAY BE ENFORCED IN OTHER JURISDICTIONS BY SUIT ON THE JUDGMENT OR IN ANY OTHER MANNER PROVIDED BY LAW. EACH PARTY IRREVOCABLY AND UNCONDITIONALLY WAIVES, AND AGREES NOT TO ASSERT, BY WAY OF MOTION, AS A DEFENSE, OR OTHERWISE, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, ANY OBJECTION THAT IT MAY NOW OR HEREAFTER HAVE (I) THAT IT IS NOT SUBJECT PERSONALLY TO THE JURISDICTION OF THE ABOVE-NAMED COURTS, THAT THE SUIT, ACTION OR PROCEEDING IS BROUGHT IN AN INCONVENIENT FORUM, THAT THE VENUE OF THE SUIT, ACTION OR PROCEEDING IS IMPROPER OR THAT THIS AGREEMENT OR THE SUBJECT MATTER HEREOF MAY NOT BE ENFORCED IN OR BY SUCH COURT AND (II) TO THE LAYING OF VENUE OF ANY ACTION OR PROCEEDING ARISING OUT OF OR RELATING TO THIS AGREEMENT IN ANY COURT REFERRED TO ABOVE. EACH OF THE PARTIES HEREBY IRREVOCABLY AND UNCONDITIONALLY WAIVES, TO THE FULLEST EXTENT PERMITTED BY APPLICABLE LAW, THE DEFENSE OF AN INCONVENIENT FORUM TO THE MAINTENANCE OF SUCH ACTION OR PROCEEDING IN ANY SUCH COURT.

18.6 Entire Agreement. This Agreement, including the Exhibits attached hereto and incorporated herein, together with the Ground Lease, contain the entire understanding of the Parties with respect to the subject matter hereof and thereof and supersede all prior and contemporaneous discussions, agreements and commitments between the Parties with respect hereto and thereto, and any prior and contemporaneous confidentiality agreements executed by the Parties in respect of the transactions contemplated by this Agreement. There are no agreements or understandings between the Parties respecting the subject matter hereof or thereof, whether oral or written, other than those set forth herein or therein, and neither Party has relied upon any representation, express or implied, not contained in this Agreement.

18.7 Amendments. This Agreement may be modified or amended only by an instrument in writing signed by the Parties hereto.

18.8 Severability. If any of the terms and conditions of this Agreement is held by any court of competent jurisdiction to contravene, or to be invalid under, the laws of any Governmental Authority having jurisdiction over the subject matter of this Agreement, such contravention or invalidity will not invalidate the entire Agreement. Instead, this Agreement will be construed as if it did not contain the particular provision or provisions held to be invalid, and an equitable adjustment will be made and necessary provisions added so as to give effect to the

intention of the Parties as expressed in this Agreement at the time of the execution of this Agreement and of any amendments to this Agreement.

18.9 Record Retention; Audit. Each Party agrees to retain all records relating to the performance of such Party's obligations hereunder for a period of 5 years from and after the creation of such records, and to cause its Affiliates to retain all such records for the same period. Either Party will have the right during such period, on an annual basis and upon reasonable prior notice, to audit the other Party's metering and other records relating to this Agreement to the limited extent necessary to verify the basis for any claim by either Party regarding payments hereunder. Each Party will make such metering and other records available at its corporate office during normal business hours and the auditing Party will reimburse the other Party for those reasonable out of pocket costs incurred by it in respect of such audit, as supported by appropriate documentation.

18.10 No Third Party Beneficiaries. This Agreement is for the sole benefit of the Parties hereto, and except as specifically provided herein, nothing in this Agreement or any action taken hereunder will be construed to create any duty, liability or standard of care to any Person not a party to this Agreement. Except as specifically provided herein, no Person not a Party hereto will have any rights or interest, direct or indirect, in this Agreement or the services to be provided hereunder, or both. The Parties specifically disclaim any intent to create any rights in any Person as a third-party beneficiary to this Agreement or the services to be provided hereunder, or both.

18.11 No Recourse. This Agreement is solely and exclusively between Buyer and Seller, and any obligations created herein will be the sole obligations of the Parties hereto. No Party will have recourse to any director, officer, Affiliate, partner, or joint venturer of the other Party for performance of said obligations, unless the obligations are assumed or guaranteed in writing by the Person against which recourse is sought.

18.12 Non-Waiver. No waiver of any of the terms of conditions of this Agreement will be effective unless in writing and signed by the Party against whom such waiver is sought to be enforced. Any waiver of the terms hereof will be effective only in the specific instance and for the specific purpose given. The failure of a Party to insist, in any instance, on the strict performance of any of the terms and conditions hereof will not be construed as a waiver of such Party's right in the future to insist on such strict performance.

18.13 Forward Contract; Forward Agreement. The Parties acknowledge and intend that this Agreement, the transactions contemplated hereby, and any instruments that may be provided by either Party hereunder will each, and together, constitute one and the same "forward contract" and "forward agreement" within the meaning of the Bankruptcy Code, and that Buyer and Seller are "forward contract merchants" and "swap participants" within the meaning of the Bankruptcy Code. Each Party agrees that it will not make any assertion or claim, in any Dispute or otherwise, or otherwise take any position to the effect that this Agreement, the transactions contemplated hereby, and any instrument(s) that may be provided by either Party hereunder do not each, and together, constitute one and the same "forward contract" and "forward agreement" within the meaning of the Bankruptcy Code, or that Buyer and Seller are not "forward contract merchants" and "swap participants" within the meaning of the Bankruptcy Code.

18.14 Expenses. Each Party will be responsible for its own costs and expenses (including the fees and expenses of its legal counsel) incurred in the preparation, review, execution and delivery of this Agreement and all related documents.

18.15 Headings. The headings to Articles, Sections and Exhibits of this Agreement are for ease of reference only and in no way define, describe, extend or limit the scope of intent of this Agreement or the intent of any provision contained herein.

18.16 Further Assurances. Each Party agrees to provide such information, execute and deliver any instruments and documents and to take such other actions as may be necessary or reasonably requested by the other Party which are not inconsistent with the provisions of this Agreement and which do not involve the assumptions of obligations other than those provided for in this Agreement, in order to give full effect to this Agreement and to carry out the intent of this Agreement.

18.17 Counterparts; Execution by Facsimile or Electronic Mail. This Agreement may be executed in one or more counterparts, all of which will be considered one and the same Agreement and each of which will be deemed an original. Delivery of an executed counterpart of this Agreement by facsimile or by electronic transmission will be equally effective as delivery of an original executed counterpart of this Agreement.

[*SIGNATURE PAGE FOLLOWS*]

IN WITNESS WHEREOF, Seller and Buyer have entered into this Agreement effective as of the Effective Date.

SELLER

DUKE ENERGY CAROLINAS, LLC

By: _____

Name: ROBERT F. CALDWELL

Title: PRESIDENT DE REP.

BUYER

CLEMSON UNIVERSITY

By: _____

Name: Brett A. Dalton

Title: Executive Vice President of Finance & Operations

EXHIBIT A

SPECIFICATIONS

Steam

DE will provide saturated steam at a nominal pressure of 325 psig and at a maximum pressure of 350 psig. The steam purity and quality will meet the specifications of CU's existing boilers and water treatment system.

DE will provide steam flow to furnish a variable CU campus steam flow rate ranging from a minimum of 20,000 lb/hr to a maximum turbine exhaust and duct burner steam output of 100,000 lb/hr to supplement CU's full peak steam requirement. The level of fresh air firing capability is 60,000 lb/hr to provide base load steam to supplement CU's other boilers when the Combustion Turbine Generator (CTG) is down.

Condensate

CU will provide condensate at nominal conditions of 120°F and 10 psig. CU plans to return 70% of the condensate but does not guarantee an amount. Condensate will be sufficiently free of impurities consistent with electric and steam generation utility practices. DE may reject condensate if it fails DE's minimum quality standards.

Make-Up Water

CU will provide all CHP make-up water from Buyer's municipal water system at nominal conditions of 75°F and 60 psig.

DE Facilities

- Building and Related Infrastructure.
- CHP Plant and Related Equipment (~16 MW GT + HRSG + Duct-Firing)
- Interconnection Facilities
    - Power connection to DE grid

CU Facilities

- Steam
- Condensate
- Make-up water
- Potable water

- Sewer connection

EXHIBIT B

SITE PLAN

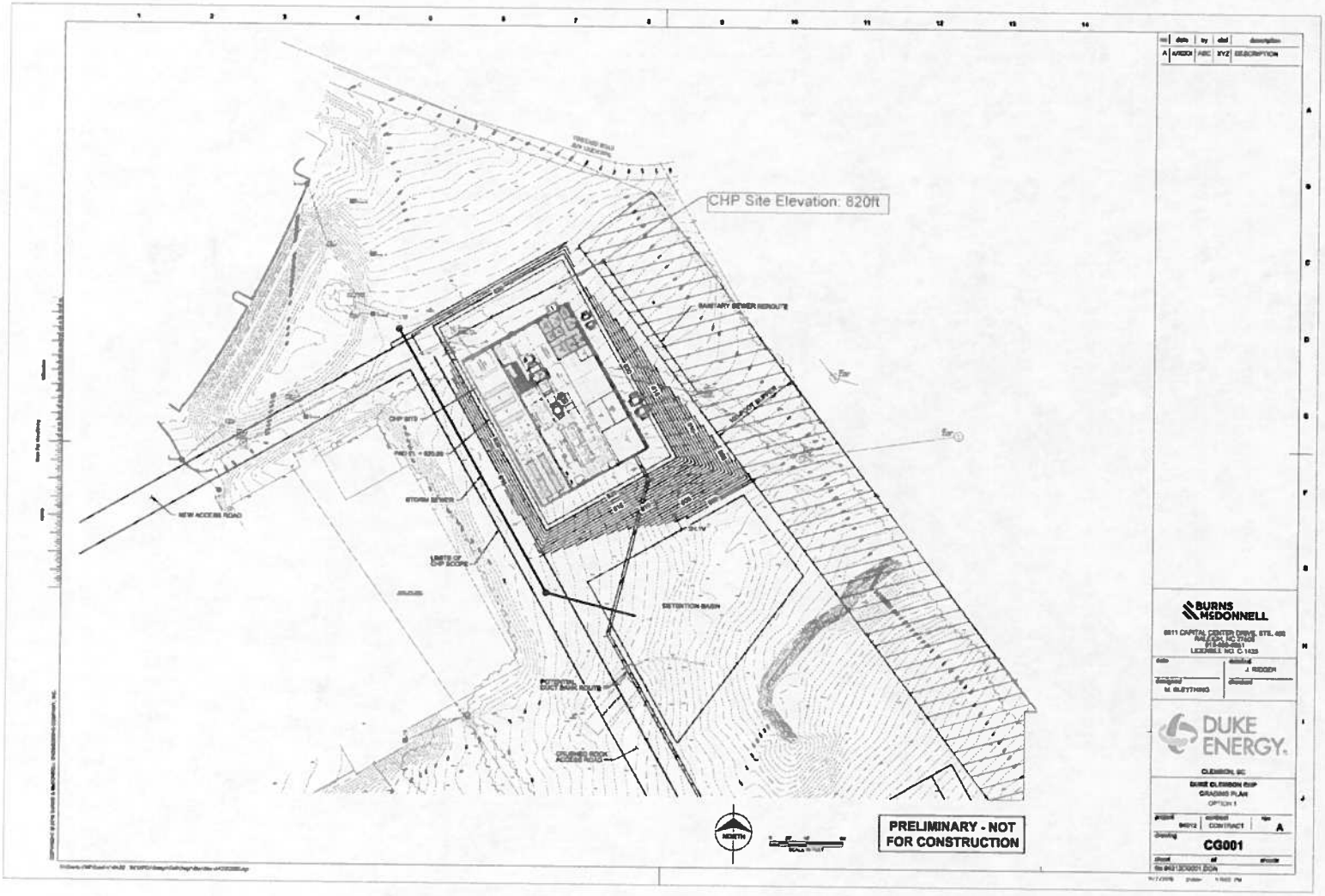

Exhibit B-1

EXHIBIT C

PAYMENT CALCULATIONS

Contract Price Formula

The price per thousand pounds of steam is the product of the natural gas price times a multiplier.

The natural gas price for each 12-month period from July 1 through June 30 (or portion thereof) during the Term will be the average of the monthly NYMEX Henry Hub (HH) contract closing prices for each month during such 12-month period, as determined on the basis of the contract closing price for each such month on the last trading day of June immediately preceding the commencement of such 12-month period. For example, the last trading day in June 2016 for the July 2016 and subsequent 11 months' NYMEX HH contracts is June 28, 2016. The natural gas price for the 12-month period from July 1, 2016 through June 30, 2017 would be the average of the contract closing prices for the monthly NYMEX HH contracts from July 2016 through June 2017, as determined on the basis of the contract closing prices on June 28, 2016.

The multiplier depends on the volume of steam delivered by DE to CU per the table below. CU will pay for at least 350,000 k#/year regardless of the actual amount it takes as long as the CHP is able to deliver this amount.

Steam k#/year		Multiplier
At Least…	But Less Than…	
350,000	400,000	2.100
400,000	450,000	1.850
450,000	482,000	1.675
482,000	530,000	1.550
530,000	n/a	1.425

For example, if the NYMEX HH 12 month strip on June 28, 2016 is $2.50/mmBtu and CU nominates to take 500,000 k# steam for the year, then CU will pay DE $1,937,500 ($2.50 x 1.550 x 500,000) in 12 equal monthly payments of $161,458. Full year payment will be trued up for the actual amount of steam.

If the NYMEX HH 12 month strip exceeds $8, DE and CU will renegotiate the Contract Price to a value that is advantageous for CU and the rest of the DE's customers if approved by the SC Public Utilities Commission.

From time to time, the Parties may agree to using a longer NYMEX HH time period such as 2-5 years for determining the natural gas price. For example, if the Parties agree to a NYMEX HH 3 year strip, then the steam price for the relevant 3-contract-year period would be fixed at that amount for all 3 years.

EXHIBIT D

TERMINATION PAYMENT AMOUNTS

Termination Payment Payable under Section 14.5:

Two times the total Contract Price (as determined in accordance with Exhibit C) for the most recently ended Contract Year.

Termination Payment Payable under Section 15.1:

Contract Years 1-10: No termination for convenience by either Party.

Contract Years 11 and later: Two times the total Contract Price (as determined in accordance with Exhibit C) for the most recently ended Contract Year.

EXHIBIT E

REQUIRED PERMITS AND APPROVALS

Task Name	Regulatory Agency	Status
Jurisdictional Determination	USACE	Only necessary if the project has the potential to impact waters of the US.
Dredge/fill permit (CWA Section 404)	USACE	Required only if the project has justifiable and unavoidable impacts to waters of the US.
Water Quality Certification (CWA Section 401)	SC DHEC	Required only if Section 404 permit is necessary.
NPDES permit (CWA Section 402)	SC DHEC	NPDES Construction General Permit may be required even for ground disturbance > 1 acre. EPC contractor to obtain including NOI and SWPPP, as needed.
Endangered Species Act	USFWS	EPC consultant to obtain concurrence letter.
National Historic Preservation Act, Section 106	SC SHPO / THPO	EPC consultant to obtain concurrence letter.
Air Emissions, Construction Permit (CAA)	SC DHEC	Duke Energy to obtain prior to construction. PSD permit is not anticipated.
Air Emissions, Operating Permit (CAA)	SC DHEC	Duke Energy to obtain and hold air operating permit.
SPCC Plan (CWA, OPA)	EPA	EPC Contractor to complete once selected.
FAA Determination	FAA	Not anticipated. Re-evaluate upon final design
Potable Water	SC DHEC	Drinking water connections to be supplied by Clemson University.
Sewage Disposal	SC DHEC	Wastewater disposal to the City of Clemson. Will require General Permit for Satellite Sewer System.
Erosion and Sedimentation Control Plan	SC DHEC	EPC Contractor to obtain permit.

USACE = U.S. Army Corps of Engineers; CWA = Clean Water Act; SC DHEC = S.C. Department of Health and Environmental Control; USFWS = U.S. Fish & Wildlife Service; SHPO/THPO = State Historic Preservation Officer / Tribal Historic Preservation Officer; EPA = Environmental Protection Agency; NPDES = National Pollutant Discharge Elimination System; NOI = Notice of Intent; PSD = Prevention of Significant Deterioration; SWPPP = Storm Water Pollution Prevention Plan; EPC = Engineering, Procurement, Construction; SPCC = Spill Prevention, Control and Countermeasures; OPA = Oil Pollution Act; FAA = Federal Aviation Administration

EXHIBIT F

NOTICES ADDRESSES

Seller: Duke Energy Carolinas, LLC

All Notices:

Street: 400 South Tryon Street

City: Charlotte, NC 28202

Attn: Director, Business Development
Phone: 704-382-9644
Facsimile: 704-382-4207
E-mail: zachary.kuznar@duke-energy.com

Buyer: Clemson University

All Notices:

Street: 310 Klugh Avenue

City: Clemson, SC 29634

Attn: Director of Utility Services
Phone: 864-656-7300
Facsimile: 864-656-0793
E-mail: Tony@clemson.edu

GROUND LEASE AND EASEMENT AGREEMENT
(CHP Facility)

This **GROUND LEASE AND EASEMENT AGREEMENT** (this "Ground Lease"), is dated as of February 2, 2017 ("Effective Date") between **Clemson University**, a body politic under the laws of the State of South Carolina ("Landlord") and **DUKE ENERGY CAROLINAS, LLC**, a North Carolina limited liability company ("Tenant").

In consideration of the mutual agreements herein contained and other good and valuable consideration, the receipt and legal sufficiency of which is hereby acknowledged, the parties hereto, intending to be legally bound hereby, hereby agree as follows:

1. Definitions. For all purposes of this Ground Lease the terms set forth in Exhibit B shall have the meanings assigned to them in said Exhibit B, and include the plural as well as the singular.

2. Lease; Terms.

2.1 Lease of Site; Terms. Landlord hereby leases the Site to Tenant, and Tenant hereby leases the Site from Landlord, upon the terms and conditions hereof, for the Development Period, and, if applicable, the Operational Term, as described below in Sections 2.1.1 and 2.1.2.

2.1.1 The Development Period (the period during which Tenant performs development activities, including but not limited to, obtaining permits, securing its position to interconnect into the grid and constructing the Facility), shall commence on the Effective Date and continue until the Target Commercial Operation Date (as defined in the SSPA). If Tenant notifies Landlord at least thirty (30) days prior to the expiration of the Development Period that Tenant has commenced construction of the Facility, then the Development Period shall not expire on its scheduled expiration date but shall be automatically extended until the occurrence of the Commercial Operation Date with respect to Facility. Tenant shall have "commenced construction" of the Facility if and when Tenant commences the grading on the Site, and is diligently pursuing construction of the Facility on the Property. The Development Period respecting the Facility shall, in all events, terminate on the Commercial Operation Date of the Facility and the Operational Term for the Facility shall commence.

2.1.2 The Operational Term (the period during which the Facility is generating and delivering Steam (as such term(s) is/are defined in the SSPA) as well as generating electricity), if it occurs, shall commence on the Commercial Operation Date for the Facility or such earlier date as designated by Tenant in writing, and continue to the date that is thirty-five (35) years following such commencement date or such earlier termination date as the parties hereto may mutually agree upon in the event of a termination of the SSPA. The Development Period and the Operational Term are herein sometimes collectively referred to as the "Term".

2.2 Force Majeure. Tenant shall have the right to terminate this Ground Lease as follows:

2.2.1 To the extent Tenant is prevented by Force Majeure Event from operating the Facility located on the Site for the purposes of generating or selling Steam to the Landlord pursuant to the SSPA, and Tenant gives notice and details of the Force Majeure Event to the Landlord as soon as practicable, then the Tenant will be excused from the performance of its obligations under this Ground Lease (other than the obligation to make payments then due or becoming due with respect to performance prior to the Force Majeure Event). The Tenant will give prompt notice to the Landlord of the Force Majeure Event and the extent of the Tenant's inability to operate the Facility and fulfill its obligations under this Ground Lease and/or the SSPA. If the Tenant provides such notice orally, the Tenant will promptly follow such oral notice with written notice provided in accordance with the requirements of this Ground Lease. The Tenant will use commercially reasonable efforts to (a) remove or remedy such inability to perform within a reasonable period of time, and (b) mitigate the impacts on the Landlord of such inability to perform. The Landlord will not be required to perform or resume performance of its obligations to the Tenant corresponding to the obligations of the Tenant excused by Force Majeure Event.

2.2.2 The Tenant will (a) promptly notify the Landlord upon the occurrence of any Force Majeure Event, which notice will indicate the scope and cause of the Force Majeure Event and the anticipated period of impact of such Force Majeure Event, (b) promptly provide such available information about the Force Majeure Event and its impact as may be reasonably requested by the Landlord and (c) provide updated information regarding such Force Majeure Event and its impact from time to time as reasonably requested or periodically (but not less than once per month) until such Force Majeure Event and its impact on the obligations of the Tenant under the terms of this Agreement and/or the SSPA cease to exist. When the Tenant is able to resume performance of its obligations under this Ground Lease and under the SSPA, it will give the Landlord written notice and the Landlord and Tenant will resume performance under the Ground Lease. Subject to Section 2.2.4 below, if any Force Majeure Event excuses performance of the Tenant's obligations under this Ground Lease or the SSPA for a period in excess of 30 days, the Term will be extended for a period equal to the period of such excused performance. The Parties will amend this Agreement in writing to reflect any such extension of the Term.

2.2.3 The suspension of performance by the Tenant due to a Force Majeure Event will be of no greater scope and no longer duration that that which is necessary. Tenant will use its commercially reasonable efforts to cure the cause(s) preventing its performance under the terms of this Ground Lease and the SSPA. When the Tenant is able to resume performance of its obligations under this Ground Lease and under the SSPA, it will immediately give the Landlord written notice to that effect and will resume such performance under this Ground Lease and the SSPA as soon as practicable after such notice is delivered. The settlement of strikes, lockouts and other labor disputes will be entirely within the discretion of the Tenant and Tenant will not be required to settle such strikes, lockouts or other labor disputes by acceding to demands which Tenant deems to be unreasonable in its sole and absolute discretion.

2.2.4 If a Force Majeure Event prevents the Tenant from performing a material obligation of Tenant under either this Ground Lease or the SSPA for a period of 12 consecutive months, then the Tenant will have the right to terminate this Ground Lease by written notice to the Landlord, in which case this Ground Lease will terminate 90 days after the date of such termination notice unless, within such 90-day period, (a) full performance has resumed hereunder or the Tenant has withdrawn such notice or (b) the Tenant demonstrates, to the reasonable satisfaction of the Landlord, that the Tenant is exercising sustained and diligent efforts to overcome the effects of the Force Majeure Event and reasonably expects that the Tenant will be able, within a period of six (6) months from the end of such 90-day period, to resume performance of the obligations affected by the Force Majeure Event. Upon the effective date of such termination, neither Party will have any further rights or obligations under this Ground Lease, except those rights and obligations arising before the effective date of such termination and except as expressly provided otherwise in this Ground Lease, and Tenant shall surrender the Site and any applicable Easement Areas pursuant to Article 6 hereof. Further, Tenant will not be liable to the Landlord for any termination payment or otherwise owe to the Landlord any damages of any kind for or as a result of such termination; *provided, however*, that such termination will not relieve either Party of any obligations or any liability arising under or in connection with this Ground Lease prior to such termination, or Tenant's obligation to surrender the Site and any applicable Easement Areas to Landlord pursuant to Article 6 hereof.

2.3 Holdover. If Tenant shall remain in possession of the Site after the expiration or termination of the Term, such possession shall be on a month-to-month tenancy, and the provisions of this Ground Lease shall remain applicable for any such term; provided that, such possession shall be subject to termination by Landlord at any time on not less that 30 days prior written notice. If Tenant fails to surrender the Site upon the expiration or termination of the Term pursuant to Section 6 hereof, in addition to any other liabilities to Landlord accruing therefrom, Tenant shall indemnify and hold Landlord harmless from any loss or liability resulting from such failure.

3. Severance. The parties agree that all improvements at any time constructed by or for Tenant on the Site or within any Easement Area, whether prior to the Effective Date or after same, and all equipment at any time acquired by or for Tenant and located on the Site or within any Easement Area, including (without limitation) all improvements and equipment comprising the Facility, are hereby severed by agreement and intention of the parties and shall remain severed from the Site and any Easement Area, shall be considered with respect to the interests of the parties hereto as the sole and exclusive property of Tenant or a Financing Party designated by Tenant, and, even though attached to or affixed to or installed upon the Site or within an Easement Area, shall not be considered to be fixtures or a part of the Site or such Easement Area and shall not be or become subject to the lien of any mortgage or deed of trust heretofore or hereafter placed on the Site or any Easement Area by Landlord.

Landlord hereby waives any rights it may have under the laws of the State of South Carolina arising under this Ground Lease or otherwise to any lien upon, or any right to distress or attachment upon, or any other interest in, any item constituting all or any portion(s) of the Facility or any other equipment or improvements constructed or acquired by or for Tenant and located on the Site or within any Easement Area.

4. Rent. Rent for the entire Term (both the Development Period and the Operational Term and any extension(s) thereof) of this Ground Lease shall consist of the payment in the amount of One Hundred and No/100 Dollars ($100.00), the receipt and sufficiency of which Landlord hereby acknowledges. Provided, however, in the event of early termination of the SSPA, and if the Landlord and Tenant mutually agree that the Facility is to remain in place after such termination, the Rent shall be modified to be the Fair Market Rental Rate as determined below:

4.1 Definition. The term "Fair Market Rental Rate" shall mean the market rental rate for the time period such determination is being made for land in the Clemson area (the "AREA") of comparable condition and of equivalent quality, size, utility, and location. Such determination shall take into account all relevant factors, including, without limitation, the following matters: the credit standing of Tenant; the length of the term (but specifically excluding the value of improvements installed in the Premises at Tenant's cost).

4.2 Determination. Landlord shall deliver to Tenant notice of the Fair Market Rental Rate (the "FMR Notice") for the Premises for the remaining applicable Operational Term in question within ten (10) days after the termination of the SSPA giving rise for the need to determine the Fair Market Rental Rate. If Tenant disagrees with Landlord's assessment of the Fair Market Rental Rate specified in a FMR Notice, then it shall so notify Landlord in writing within ten (10) business days after delivery of such FMR Notice; otherwise, the rate set forth in such notice shall be the Fair Market Rental Rate. If Tenant timely delivers to Landlord notice that Tenant disagrees with Landlord's assessment of the Fair Market Rental Rate, then Landlord and Tenant shall meet to attempt to determine the Fair Market Rental Rate. If Tenant and Landlord are unable to agree on such Fair Market Rental Rate within ten (10) business days after Tenant notifies Landlord of Tenant's disagreement with Landlord's assessment thereof, then Landlord and Tenant shall each appoint an independent real estate appraiser with an MAI designation and with at least ten (10) years' commercial real estate appraisal experience in the AREA market. The two appraisers shall then, within ten (10) days after their designation, select an independent third appraiser with like qualifications. Within twenty (20) business days after the selection of the third appraiser, a majority of the appraisers shall determine the Fair Market Rental Rate. If a majority of the appraisers is unable to agree upon the Fair Market Rental Rate by such time, then the two (2) closest appraisals shall be averaged and the average will be the Fair Market Rental Rate. Tenant and Landlord shall each bear the entire cost of the appraiser selected by it and shall share equally the cost of the third appraiser.

4.3 Annually thereafter, the Fair Market Rental Rate payable by Tenant hereunder shall be increased in an amount equal to the product of the Fair Market Rental Rate times a number equal to the percentage increase in the CPI over a 12 month period, calculated by using the most recently published CPI and the CPI published 12 months earlier. As used herein, "CPI" shall mean Consumer Price Index for All Urban Consumers for the metropolitan area in which the property (Premises) is located or to which it is closest in proximity, published by the Bureau of Labor Statistics, United States Department of Labor.

5. Further Assurances. Landlord and Tenant each agree to execute and deliver all further instruments and documents and take any further action that may be reasonably necessary to effectuate the purposes and intent of this Ground Lease regarding the Facility. To such end, Landlord shall grant to Tenant and Tenant's Parties, or to such entity as Tenant may reasonably request, at no additional consideration, temporary, nonexclusive easements and rights-of-way in, to, over, under and across the Site and, as applicable, within the Building(s), and/or adjacent lands owned or controlled by Landlord, and any improvements thereon, as Landlord and Tenant deem reasonably necessary or desirable in connection with the development, construction, ownership, operation, maintenance and expansion of the Facility (the "Operational Easements") as well as an easement for purposes of interconnection with Tenant's main distribution system (the "Electrical Interconnection Easement") (the Operational Easements and the Electrical Interconnection Easement herein collectively referred to as the "Easements", each also herein sometimes referred to as an "Easement" and the area(s) burdened thereby, the "Easement Areas"). All Easements associated with the operation of the Facilities shall automatically terminate as of the date the Term terminates or expires, inclusive of any recognized and permitted holdover period. Upon request by Tenant, Landlord will execute one or

more easement agreements reflecting the Operational Easements and the Electrical Interconnection Easement, which easement agreements shall be recorded in the Official Records at Tenant's expense. Landlord shall not grant or convey any easement or other interest that, if used or enjoyed in accordance with its terms: (i) would materially interfere with Tenant's operation, use and enjoyment of the Facility, the Site, and/or the Easements, Tenant's performance under the terms of the SSPA, or Tenant's production of electricity at the Site, (ii) would materially interfere with Landlord's operation, use and enjoyment of Landlord's Property, or (iii) would materially adversely affect Landlord's title to the Site, the reversionary interest therein, or Landlord's interest under the Ground Lease. If there are any mortgages, deeds of trust or other security interests or the like encumbering the Site (or any portion(s) thereof) or any Easement Area which would have priority over this Ground Lease, within 30 days after Tenant's written request, Landlord shall obtain a commercially reasonable subordination, non-disturbance and attornment agreement, in a form satisfactory to Tenant, from any lender or beneficiary which provides, among other things, that Tenant's occupancy or use of the Site and the Easements in accordance with the terms of this Ground Lease and any applicable Easement(s) will not be disturbed. Landlord reserves to itself, its successors and assigns, together with the right to grant and transfer all or a portion of the same, the following (collectively, "Landlord Easements"): nonexclusive easements for ingress and egress and for the installation, placement, maintenance and replacement of electric, gas, telephone, cable television, water and sanitary sewer lines, drainage facilities or any other utilities (collectively, "Landlord Utilities"), and of landscaping on, over, under or across those portions of the Site not improved with the Facility or other major structures existing from time to time pursuant to the terms and conditions of this Ground Lease, together with the right, at reasonable times, to enter upon the Site in order to service, maintain, repair, reconstruct, relocate or replace any of such Landlord Utilities or landscaping. In using the rights reserved hereunder, Landlord agrees that such use shall be at times and in a manner that will reasonably cause the least amount of disruption to the operations on the Site.

6. Surrender of Site. Upon expiration of the Term or earlier termination of this Ground Lease with respect to the Facility for any reason, Tenant shall surrender to Landlord the Site and any applicable Easements related to the Site, as provided in this Article 6. In accordance with and subject to the terms of Section 3 above, within 60 days after the termination or expiration of the Term, Tenant shall commence to decommission, dismantle and remove the Facility and all other property of Tenant located on the Site and the applicable Easement Areas, returning same to their condition as of the Effective Date to the extent reasonably practical, and shall complete such decommissioning, dismantling and removal within 270 days of commencement of the work, or such other period of time as may be agreed to by Landlord. Landlord hereby grants to Tenant and Tenant's Parties a license to enter upon the Site and the Easement Areas to perform the activities required to be performed by Tenant pursuant to this Article 6, which license shall be effective commencing upon the date of termination or expiration of the Term and shall terminate upon the date on which such decommissioning, dismantling and removal activities are complete.

7. Nontermination. Except as specifically provided to the contrary in this Ground Lease or any instruments creating the Easements, this Ground Lease shall not terminate, nor shall Tenant's interest in the Site, the Easements, or the Facility be extinguished, lost, conveyed or otherwise impaired, or be merged into or with any other interest or estate in the Site, the Easement Areas or any other property interest, in whole or in part, by any cause or for any reason whatsoever.

8. Possession and Quiet Enjoyment. As long as no Tenant Event of Default under this Ground Lease has occurred and is continuing beyond any applicable cure period, Landlord covenants and agrees that Tenant shall enjoy quiet possession of the Site and the Easements without any disturbance from Landlord or any person lawfully claiming by or through Landlord except as expressly set forth in this Ground Lease.

9. Use of Site; Development of Facility.

9.1 Use. During the Term, Tenant shall have exclusive use of the Site except as expressly set forth in this Ground Lease. Tenant may use the Site and the Easement Areas for purposes related to due diligence investigations and studies, and the construction, use, operation, repair, ownership, replacement, expansion, modification, upgrade or maintenance of the Facility.

9.2 Construction of the Facility.

(a) General Provisions. Tenant, at its expense, shall be responsible for obtaining any Governmental Approvals (hereinafter defined) necessary for the construction and operation of the Facility. To the extent permitted by law, all permits, licenses, exemptions and certifications for the construction of the Facility shall be in the name of and for the benefit of Tenant or a party designated by Tenant.

(b) Facility.

(i) Landlord shall ensure that neither Landlord nor any other person or entity claiming by or through Landlord shall interfere with or obstruct in any way Tenant's use of the Site for the construction, installation, maintenance, repair or replacement of the Facility except as expressly set forth in this Ground Lease. Without limiting the generality of the foregoing, Landlord shall not locate any new equipment, construct any new improvements, or relocate any existing equipment or other improvements upon the Site (or permit any other person or entity to do so) without Tenant's prior written consent, which consent shall not be unreasonably withheld or delayed.

(ii) All improvements and alterations to the Site and the electrical interconnection facilities located within the Electrical Interconnection Easement Area shall be made in accordance with the Manual for Planning and Execution of State Permanent Improvements (the "Manual") published by Office of the State Engineer ("OSE"), including without limitation all applicable codes and standards described in Chapter 5 thereof. Prior to any installation or alterations of the Facility, Tenant will submit detailed engineering plans to Landlord and OSE for review and approval. Tenant will not commence any installation or alteration work until Landlord is reasonably satisfied that the installations or alterations can be completed and the equipment installed can be operated and maintained without unreasonable interference with Landlord's operations at its site, and both OSE and Landlord's planning office have approved all construction plans and specifications in accordance with the Manual or any applicable approved deviation therefrom.

(iii) All improvements to the Facility located within the Site and the electrical interconnection facilities located within the Electrical Interconnection Easement Area shall be at Tenant's expense, and the installation of all such improvements shall be at the discretion and option of the Tenant. Tenant shall have the right to replace, repair, add or otherwise modify its equipment or any portion(s) thereof, whether the equipment is specified or not on any exhibit attached hereto, during the Term of this Ground Lease provided such activities are performed in compliance with the Manual or as otherwise approved by Landlord and OSE. Landlord will, at its sole cost and expense, install, own, operate, maintain, repair, and, as necessary, replace all portions of the Condensate Interconnection Facilities (as defined in the SSPA) located anywhere external to the Site.

(iv) Tenant will maintain the Facility, the Steam lines and all other lines and connections on the Site or within the Electrical Interconnection Easement Area in good condition, reasonable wear and tear excepted. Landlord shall maintain the Steam lines and all other lines and connections on Landlord's Property or the Easement Areas (other than the electrical interconnection lines within the Electrical Interconnection Easement Area) in good condition, reasonable wear and tear excepted.

(v) At all times during the Term, Landlord shall not take or permit any action on or about the Site or any Easement Area that would obstruct the proper operation of or materially reduce the effectiveness or efficiency of the Facility.

(vi) As of the date of this Lease, Landlord represents that there are no installations, equipment or facilities of any type or nature on the Site or within the Electrical Interconnection Easement Area which will materially interfere with Tenant's use and operation of the Facility, fulfilling its obligations under the SSPA or producing and delivering electricity throughout the Term. Landlord and Tenant acknowledge and agree that there will not be an adequate remedy at law for noncompliance with the provisions of this Section, and therefore Tenant shall have the right to equitable remedies, including without limitation the remedies of injunctive relief and specific performance to enjoin any use that has a material adverse effect on or results in a material interference with Tenant's business or operations at the Site or the amount of Steam or electricity generated by the Facility.

(vii) Tenant conducts criminal background checks on its employees in accordance with its policies and procedures, and will refrain bringing or sending the employee(s) to the Site, Clemson University or other property owned by Landlord that Tenant reasonably believes poses a threat to property or persons. Tenant agrees to impose this same criminal background check requirement on any contractors used by Tenant in fulfillment of its responsibilities under this agreement. Landlord reserves the right to verify compliance by Tenant upon request.

(viii) It is understood and agreed that Tenant shall be permitted to use contractors to perform its obligations under this Ground Lease. Notwithstanding the use of contractors engaged by Tenant, Tenant shall remain fully liable for the performance of its obligations and such delegation shall not relieve Tenant from any of Tenant's obligations or liabilities under this Ground Lease. Tenant shall cause the contractor to comply with the terms and conditions of this Ground Lease in the performance of any work performed hereunder.

(c) Governmental Approvals. It is understood and agreed that Tenant's ability to use the Site is contingent upon its obtaining, after the execution date of this Lease, all of the certificates, permits and other approvals, including but not limited to, approval of the state regulatory commission, that may be required by any Federal, State or Local authorities (collectively the "Governmental Approvals") in order to permit Tenant's use of the Site or the Easement Areas as set forth above. At Tenant's request, Landlord shall, at no additional expense to Landlord, cooperate with Tenant in obtaining such Governmental Approvals and shall join with Tenant in all such applications and proceedings required by Tenant to facilitate the issuance of such Governmental Approvals. In the event that any of such applications for such Governmental Approvals should be finally rejected prior to the expiration of the Development Period or in the event Tenant determines that such Governmental Approvals may not be obtained prior to the expiration of the Development Period, Tenant shall have the right to terminate this Ground Lease. Notice of the Tenant's exercise of its right to terminate pursuant to the foregoing sentence shall be given to Landlord in writing prior to the expiration of the Development Period.

9.3 Maintenance. During the Term, Tenant shall be responsible, at its sole cost and expense, for the general maintenance of the Site in a good condition and repair in accordance with first-class standards consistent with the maintenance of Landlord's Property. Landlord is not obligated to repair, replace or maintain the Site.

9.4 Access. During the Term, Landlord shall allow (and Tenant may construct) a permanent means of ingress and egress to and from the Facility between the Facility and the most convenient public road (or private road consistently maintained by Landlord and constantly available for Tenant's use) which shall be operated and maintained by Tenant and shall be cleared, graded, improved and maintained with a surface passable at all times by a two-wheel drive vehicle. The improvements to the ingress and egress area shall be made in accordance with the Manual published by OSE, including without limitation all applicable codes and standards described in Chapter 5 thereof. Prior to any installation of such improvements, Tenant will submit detailed engineering plans to Landlord and OSE for review and approval, including the location of such ingress and egress improvements. Tenant will not commence any installation work until Landlord is reasonably satisfied that the installations can be completed and the equipment installed can be operated and maintained without unreasonable interference with Landlord's operations at its site, and OSE and Landlord's planning office has approved all construction plans and specifications in accordance with the Manual, such approval by Landlord's planning office not to be unreasonably withheld, conditioned or delayed (it being acknowledged that Landlord has no control over the approval of the construction plans and specifications by the OSE).

9.5 Liens. Tenant shall keep the Site and Easement Areas free and clear of any lien or encumbrance arising out of work performed, materials furnished or obligations incurred in connection with Tenant's obligations for construction, utilities and services, repairs or alterations under this Ground Lease. In the event any lien is placed upon the Site or Easement Areas as a result of any act or omission of Tenant, Tenant shall pay such lien or may provide a bond or otherwise insure Landlord against such lien within 60 calendar days after notice to Tenant of such lien being perfected, and may thereafter contest such lien or payment at Tenant's sole cost and expense. Tenant shall indemnify Landlord against any loss, damage, cost or expenses in connection with any such lien or encumbrance that may be claimed or asserted against the Site or Easement Areas. If Tenant fails to discharge any lien created or established in violation of Tenant's covenant herein, Landlord, without declaring a default hereunder

and without relieving Tenant of any liability hereunder, may, but shall not be obligated to, discharge or pay such lien (either by paying the amount claimed to be due or by procuring the discharge of such lien by deposit or by bonding proceedings), and any amount so paid by Landlord and all costs and expenses incurred by Landlord in connection therewith shall be paid immediately by Tenant to Landlord upon demand.

10. Insurance.

10.1 Tenant's Coverage. Tenant will maintain during the term of this Lease, and will require any general contractor of Tenant retained to perform significant construction or demolition work at the Facility or on the Site to maintain during the term of such work, the insurance coverage set forth below with insurance companies having an A.M. Best credit rating of "A-, VII" or better, with minimum coverage limits indicated below on policies issued on an "occurrence" basis, and naming Landlord and Tenant, and their respective officers, directors, shareholders, agents, independent contractors and Affiliates as additional insureds for ongoing and completed operations on all policies except workers compensation and employers liability:

(a) Umbrella Insurance Coverage. Umbrella insurance coverage in the amount of $5,000,000 and excess or umbrella liability insurance coverage with a limit of not less than $5,000,000 per occurrence and per project. These limits will apply in excess of each of the below mentioned policies.

(b) Commercial General Liability. Commercial general liability insurance that covers bodily injury, personal injury, and property damage, including products liability and contractual liability coverage, with per occurrence limits of not less than $1,000,000 and an aggregate limit of not less than $2,000,000 and (x) which will include "contractual" coverage for the indemnity clause set forth in Section 12.1(a) below, and (y) with coverage written on a primary and non-contributory basis.

(c) Property Insurance. Commercial property insurance insuring all improvements, fixtures and personal property located on the Site from time to time in an amount equal to 100% of the full replacement cost thereof, subject to a deductible reasonably acceptable to Landlord; said commercial property insurance policy will insure against the perils of fire and extended coverage and will include "special form" property insurance for physical loss or damage including, without duplication of coverage, theft, vandalism and malicious mischief carried with a reputable insurance company authorized or qualified to do business in the State of South Carolina ("State").

(d) Workers' Compensation Insurance. Workers' compensation insurance (or qualification as a self-insurer) covering its employees in amounts at least equal to the minimum coverage amounts provided under the laws of South Carolina, notwithstanding any provision limiting requirements to a particular number of employees. Seller will provide for, or require any Subcontractor (as defined below) to maintain, similar coverage for the Subcontractor's employees employed in connection with this Agreement. The insurance required under this Section 10.1(d) will bear an endorsement evidencing a waiver of the right of subrogation against Landlord.

(e) Employers' Liability Insurance. Employers' liability insurance that covers both "bodily injury by accident" and "bodily injury by disease" with limits of not less than $1,000,000 each accident/$1,000,000 disease policy limit/$1,000,000 each employee.

(f) Automobile Liability Insurance. Automobile liability insurance coverage (including coverage for claims against Tenant for injuries to employees of Landlord or any of its subcontractors) for owned, non-owned, and hired autos with a limit of not less than $1,000,000 per accident.

(g) Builder's Risk Insurance. During any period within which any construction or installation of any improvements, fixtures or personal property at the Site is taking place, "special form" builder's risk insurance upon such improvements, fixtures or personal property to the full replacement value thereof. Said builder's risk insurance policy will insure against the perils of fire and extended coverage and will include "special form" builder's risk insurance for physical loss or damage including, without duplication of coverage, theft, vandalism and malicious mischief.

(h) Policy Terms. The liability policy carried by Tenant as described above (a) shall be primary with respect to any other insurance which may be carried by Landlord, and (b) shall include Landlord, as an additional insured.

10.2 Landlord's Coverage. Landlord shall maintain Commercial General Liability Insurance covering legal liability for bodily injury (including death), property damage and personal injury in an amount not less than one million dollars ($1,000,000) per occurrence. This insurance shall include under each of its respective policies its employees with respect to their participation in this Agreement while they are carrying out their official duties for the Landlord.

10.3 Certificates. Prior to commencement of construction of the Facility, Tenant shall provide Landlord with written evidence of the insurance required in Section 10.1 above in the form of appropriate insurance certificates specifying amounts of coverage and expiration dates of all policies in effect. Tenant agrees to make Landlord an additional insured on Tenant's commercial general liability and automobile liability policies, and will provide Landlord with copies of policy endorsements reflecting Landlord's status as an additional insured thereunder. With respect to the insurance provided to Landlord hereunder, (i) Tenant will procure from each insurer a waiver of subrogation in Landlord's favor and (ii) such insurance will be primary to any other insurance carried by Landlord. Insurance coverage provided by Tenant under this section will not include any of the following: (i) any claims made insurance policies; (ii) any self-insured retention or deductible amount greater than $250,000.00, unless approved in writing by Landlord; (iii) any endorsement limiting coverage available to Landlord which is otherwise required by this section; and (iv) any policy or endorsement language that (A) limits the duty to defend Landlord under the policy or (B) provides coverage to Landlord only if Tenant is negligent.

10.4 Full Limits Coverage. Notwithstanding the minimum limits of coverage set forth above, Tenant will name Landlord, its officers, directors, employees, subsidiaries, successors, and assigns as additional insureds for the full limits of insurance coverage purchased by Tenant. The additional insured coverage provided pursuant to this Section 10.4 will provide coverage to Landlord for all claims, losses, demands, liens, causes of action or suits, judgments, fines, assessments, liabilities, damages and injuries (including death) covered by Article 12 herein below. Tenant is responsible for payment of all deductibles, self-insured retentions or similar charges for the additional insured coverage required pursuant to this Section 10.4.

10.5 Waiver of Insurance; Right to Self-Insure. In the event any insurance (including the limits of deductibles thereof) hereby required to be maintained, other than insurance required by law to be maintained, shall not be commercially available and commercially feasible in the commercial insurance market, in Tenant's reasonable determination, Tenant shall advise Landlord of same explaining in detail the basis for such conclusions. In such event, the applicable requirement shall be deemed waived, and Tenant shall be deemed to self-insure for such coverage(s). Any such waiver shall be effective only so long as such insurance shall not be available and commercially reasonable, in Tenant's reasonable discretion. Notwithstanding anything herein to the contrary, so long as Tenant is an affiliate of Duke Energy Corporation ("DEC"), Tenant shall have the right to self-insure through DEC as to any insurance required hereunder. With respect to any self-insurance by any Tenant, (i) such self-insurance by Tenant must be permitted by all federal, state, county, municipal and other governmental statutes, laws, rules, orders, regulations and ordinances affecting the Site and the Facility or otherwise applicable to Tenant, (ii) Tenant shall maintain a tangible net worth of at least Five Hundred Million and no/100 Dollars ($500,000,000.00), and (iii) Tenant will protect Landlord to the same extent as it would if it had the insurance policies required hereunder. If and when Tenant shall elect to self-insure through DEC, then Tenant shall give notice thereof to Landlord which notice shall certify that the net worth of Tenant is not less than $500,000,000.00. In additional, simultaneously with the delivery of said notice, Tenant shall deliver to Landlord unaudited financial statements for Tenant for the most recent fiscal year, which financial statements shall be prepared in accordance with generally accepted accounting principles and certified as true and correct by an officer or partner of Tenant, and Tenant shall provide updated financial statements within thirty (30) days after a written request therefore from Landlord (such request to be made not more frequently than once every twelve (12) month cycle) so long as the Tenant continues to self-insure. The minimum amounts of insurance coverage required hereunder will not be construed to create a limit on Tenant's liability with respect to its indemnification obligations hereunder. The foregoing right of any Tenant that is not an affiliate of DEC to self-insure will not apply with respect to insurance coverage related to accidental death and dismemberment, which policy will at all times be maintained with a third party provider and will consist of coverage that is consistent with the requirements set forth in Section 10.1(b).

10.6 Right to Cure. If a Party fails to procure or maintain any insurance required pursuant to Article 10, the other Party will have the right, but not the obligation, upon not less than 30 days prior written notice from such other Party to the non-performing Party, to procure such insurance on behalf of the non-performing Party and in any such event such other Party will be entitled to recover the premiums paid for such insurance as an amount due under this Lease.

11. Damage or Destruction of Facility. If, at any time during the term of this Ground Lease, the Facility shall be wholly or partially damaged or destroyed by Casualty, then Tenant shall cause the same to be repaired, replaced, or rebuilt in accordance with this Article 11 and all requirements of Section 9.2 within twelve (12) months after the occurrence of the damage or destruction. The repairs shall restore the Facility to a condition which is not less than the condition it was in immediately prior to the Casualty. The repairs shall be made in a good and workmanlike manner using new, quality materials, products and equipment; and the Facility, after completion of the repairs, shall conform and otherwise comply in all material respects with all applicable laws. All insurance proceeds paid by Tenant's insurers on account of the Casualty shall be paid to Tenant as its sole property, to be used by Tenant in connection with repairing the Facility, if applicable. Notwithstanding anything to the contrary contained herein, Tenant shall have the option to terminate this Lease by written notice to Landlord given within ninety (90) days after the occurrence of any material damage or destruction that renders the Facility unfit, in Tenant's commercially reasonable discretion, for the generation and delivery of Steam, if the damage or destruction occurs within the last sixty (60) months of the Term of this Ground Lease and Tenant shall surrender the Site and the Easement Areas as provided in Article 6 above.

12. Liabilities.

12.1 General.

(a) Tenant shall indemnify, defend and hold Landlord and Landlord's Parties harmless from any and all third party claims, losses, expenses, liabilities, actions, suits, or judgments for personal injury or property damage (collectively, "Losses") by reason of, resulting from, whether directly or indirectly, or arising out of or related to (i) Tenant's or Tenant's Parties' ownership, operation, use or maintenance of the Facility, the Easement Areas or the Site; (ii) the negligence or willful misconduct of Tenant or any Tenant Party in connection with the transactions contemplated by this Ground Lease; (iii) any release of Hazardous Materials on the Site caused or permitted by Tenant or any Tenant Party; or (iv) any environmental claim from a third party with regard to a violation or alleged violation of any Environmental Laws by Tenant or any Tenant Party.

(b) The provisions of this Section 12.1 shall survive the expiration or termination of the Term.

12.2 Consequential Damages. Notwithstanding anything to the contrary in this Ground Lease, neither Party hereto shall be liable to the other for consequential or punitive damages, including but not limited to loss of use or loss of profit or revenue.

13. Default.

13.1 Events of Default. The following events shall be deemed to be events of default by Tenant ("Tenant Events of Default") under this Ground Lease:

(a) Failure to pay any payment required to be made hereunder, including taxes or any other sum to be paid hereunder within 20 Business Days after the date the same is due which shall have remained unpaid for 20 Business Days after written notice of such failure has been given to Tenant by Landlord.

(b) Failure to comply in any material respect with any material term, provision or covenant of this Ground Lease, other than the payment of sums to be paid hereunder, without curing such failure within 60 days after due written notice thereof from Landlord to the extent such failure is capable of being cured within such 60 day period; or if such failure cannot reasonably be cured within the said 60 days and Tenant shall not

have commenced to cure such failure within said period and shall not thereafter with reasonable diligence and good faith proceed to cure such failure.

(c) Any Event of Default (as defined in the SSPA) by Tenant under the SSPA.

(d) Tenant shall file in any court pursuant to any statute, either of the United States or any state, a petition in bankruptcy or insolvency, or for reorganization, or for the appointment of a receiver or trustee of all or any portion of Tenant's property, or makes an assignment for benefit of creditors; or there is filed against Tenant in any court pursuant to any statute either of the United States or any state, a petition in bankruptcy or insolvency, or for reorganization, or for the appointment of a receiver or trustee of all or any portion of Tenant's property, and within 90 days after the commencement of any such proceeding against Tenant, such petition shall not have been dismissed.

13.2 Landlord's Remedies. Upon the occurrence of any Tenant Event of Default, Landlord may, at its option, and in addition to and cumulatively of any other rights Landlord may have at law or in equity or under this Ground Lease, (a) cure the Tenant Event of Default on Tenant's behalf, in which event Tenant shall reimburse Landlord on demand for all reasonable sums so expended by Landlord or Landlord may elect to offset any such reasonable amounts against subsequent installments of any sums due from Landlord to Tenant hereunder or under the SSPA, (b) enforce, by all proper and legal suits and other means, its rights hereunder, including the collection of sums due hereunder, in which event Landlord shall have all remedies available at law or in equity, and should it be necessary for Landlord to take any legal action in connection with such enforcement, the Tenant shall pay Landlord all reasonable attorney's fees and expenses incurred in such legal action (as determined in the discretion of the court hearing such matter), all without prejudice to any remedies that might otherwise be used by Landlord for recovery or arrearages of sums due hereunder, damages as herein provided, or breach of covenant. Notwithstanding the forgoing, in the event of a bona fide dispute between the Parties regarding an alleged default by Tenant hereunder or under the SSPA, Landlord's remedies as to the default shall not commence until ten (10) business days after a final determination has been made by a court of competent jurisdiction in Landlord's favor.

13.3 Landlord Events of Default. The following events shall be deemed to be events of default by Landlord ("Landlord Events of Default") under this Ground Lease:

(a) Failure to pay any payment required to be made hereunder within 20 Business Days after the date the same is due which shall have remained unpaid for 20 Business Days after written notice of such failure has been given to Landlord by Tenant.

(b) Failure to comply in any material respect with any material term, provision or covenant of this Ground Lease, other than the payment of sums to be paid hereunder, without curing such failure within 60 days after due written notice thereof from Tenant; or if such failure cannot reasonably be cured within the said 60 days and Landlord shall not have commenced to cure such failure within said period and shall not thereafter with reasonable diligence and good faith proceed to cure such failure.

(c) Any act or omission of Landlord that in any way, directly or indirectly, materially adversely impacts, materially affects or materially impairs Tenant's ability to operate the Facility and/or the operation of the Facility for Tenant's contemplated use thereof.

13.4 Tenant's Remedies. Upon the occurrence of any Landlord Event of Default, Tenant may, at its option, and in addition to and cumulatively of any other rights Tenant may have at law or in equity or under this Ground Lease, (a) cure the Landlord Event of Default on Landlord's behalf, in which event Landlord shall reimburse Tenant on demand for all reasonable sums so expended by Tenant or Tenant may elect to offset any such reasonable amounts against subsequent installments of any sums due from Tenant to Landlord hereunder, or (b) enforce, by all proper and legal suits and other means, its rights hereunder, including the collection of sums due hereunder, in which event Tenant shall have all remedies available at law or in equity, all without prejudice to any remedies that might otherwise be used by Tenant for recovery or arrearages of sums due hereunder, damages as herein provided, or breach of covenant. Notwithstanding the forgoing, in the event of a bona fide dispute between the Parties regarding an alleged default by Landlord hereunder or under the SSPA, Tenant's remedies as to the

default shall not commence until ten (10) business days after a final determination has been made by a court of competent jurisdiction in Tenant's favor.

14. Governing Law. This Ground Lease and all provisions hereof, shall be governed by and interpreted in accordance with the laws of the State of South Carolina.

15. Condemnation. If at any time the Site, the Easements, or any portion thereof is condemned or transferred in lieu of condemnation, the net proceeds of such condemnation or transfer shall be divided between Landlord and Tenant (or Tenant's designee) in the proportions specified in the condemnation award or agreement of transfer or, if not so specified, in proportion to the fair value of Landlord's and Tenant's respective interests in the Site and the Easements, provided that to the extent that the net proceeds of any condemnation or transfer in lieu of condemnation are attributable to the Facility or improvements constructed by or on behalf of Tenant on the Site and/or the Easements, such proceeds shall be paid solely to Tenant or Tenant's designee, with Landlord receiving any proceeds attributable solely to the residual value of the fee estate of the Site. For the purpose of this Article 15 the net proceeds of a condemnation or transfer in lieu of condemnation shall mean the total proceeds of such condemnation or transfer less the costs and expenses incurred in connection therewith (including legal fees). If the entire Site is condemned or transferred in lieu of condemnation, the Term shall terminate at the time title vests in the condemning authority. If a portion of the Site is condemned or transferred in lieu of condemnation, the Lease shall continue in full force and effect with respect to that portion of the Site which has not been so condemned or transferred. Notwithstanding the foregoing, Tenant may terminate this Ground Lease without penalty by giving written notice of termination to Landlord if, in Tenant's reasonable discretion, the Site or the Easements are not suitable for Tenant's intended use following such condemnation or transfer in lieu thereof.

16. Maintenance Responsibilities of Parties. No party shall have any duty or responsibility to the other Party in respect of the Site or the Easement Areas or the use, maintenance or condition thereof except such obligations of such Party as are specifically set forth in this Ground Lease, the SSPA, or any instrument creating the Easements.

17. Mortgage of Tenant's Interest.

17.1 Provided Tenant is not in default of its obligations under this Lease or the SSPA beyond any applicable cure periods, Tenant may at any time, with prior written notice to Landlord, elect to finance a portion of the cost of the Facility with one or more financial institutions, leasing companies, institutions or affiliates or subsidiaries thereof (each a "Financing Party," collectively, the "Financing Parties") and in connection therewith Tenant would enter into various agreements and execute various documents relating to such financing, which documents may, among other things, assign Tenant's interests under this Ground Lease and the Easements to a Financing Party or grant a first priority security interest in Tenant's interest in the Facility and/or this Ground Lease and Tenant's other interests in and to the Site, including, but not limited to, any easements, rights of way or similar interests (such documents, "Financing Documents"). Landlord acknowledges notice of the foregoing and, subject to the provisions of this Article 17, consents to the foregoing actions and Financing Documents described above, provided that in no event shall Tenant be released from any liability under this Ground Lease and in no event shall Landlord's fee interest in the Site or land underlying any easements, rights of way or similar interest be encumbered by such Financing Documents. Upon reasonable prior notice to Landlord, Landlord agrees to execute, and agrees to use good faith reasonable efforts to obtain from any and all of Landlord's lenders, such subordination agreements, consents, estoppels and other acknowledgements of the foregoing as Tenant or the Financing Parties may reasonably request and which are reasonably acceptable to Landlord and its lenders. Landlord agrees that if requested in writing by Tenant, Landlord will thereafter furnish the Financing Parties with a counterpart of each notice or other document delivered by Landlord to Tenant in connection with this Ground Lease.

17.2 Provided Landlord has been provided with written notice by a Financing Party requesting that the Financing Party be given notice of a default by Tenant under this Lease, Landlord agrees that it shall not terminate this Ground Lease unless it has given each such Financing Party at least 30 days' prior written notice of its intent to terminate this Ground Lease, or such longer period (not to exceed ninety (90) days) in the event Financing Party may need to acquire the rights of the Tenant under the Ground Lease and possession of the Site in order to cure such default, and the Financing Party fails to cure the condition giving rise to such right of termination within such time

period, as same may be extended; provided that, in no way shall Landlord be liable to any Financing Party for failure to give notice as provided herein.

17.3 If the default under this Ground Lease is of such a nature that it cannot be practicably cured without first taking possession of the Facility and the Site or if such default is of a nature that is not susceptible of being cured by a Financing Party and provided Landlord has been provided with written notice by a Financing Party requesting that the Financing Party be given notice of a default by Tenant under this Lease, then Landlord shall not be entitled to terminate this Ground Lease by reason of such default if and so long as the Financing Party proceeds diligently (but in no event more than 30 days after Landlord delivers notice of a default by Tenant under this Lease to the Financing Party) to attempt to obtain possession of the Facility and the Site pursuant to the rights of the Financing Party under the Financing Documents and upon obtaining such possession, the Financing Parties shall proceed diligently to cure such default.

17.4 A Financing Party shall not be required to continue to proceed to obtain possession, or to continue in possession of the Site, pursuant to Section 17.3 if and when such default is cured. If the Financing Party, or a purchaser through foreclosure under the Financing Documents or otherwise, shall (a) acquire title to the Facility and the Tenant's leasehold estate created by this Ground Lease, (b) cure all defaults (including without limitation, the payment of all monetary obligations of Tenant due under the Lease), (c) assume all the obligations of Tenant hereunder, and (d) provide Landlord with adequate assurances, as determined in Landlord reasonable discretion, that the obligations of the Tenant to provide Landlord services under the SSPA shall continue uninterrupted notwithstanding the acquisition of the Facility and the Tenant's leasehold estate, then Landlord shall recognize the Financing Parties or such purchaser, as the case may be, as if such party had been the Tenant under this Ground Lease; provided, however, that Landlord's recognition of the Financing Party or its purchaser pursuant to this Section 18.4 shall not constitute a waiver of such default and Landlord's rights as a result thereof as against Tenant.

18. Landlord's Representations and Covenants.

18.1 Condition of Title; Authority; Enforceability. Landlord represents as of the Effective Date that Landlord owns fee title to the Site and the Easement Areas free and clear of any lien, interest or encumbrance, subject only to all matters and exceptions of public record or disclosed by an accurate survey (the "Permitted Exceptions"). At any time on or after the Effective Date Tenant may obtain for itself and/or any Financing Party, at Tenant's expense, an ALTA Extended Coverage policy of title insurance in a form and with exceptions acceptable to Tenant in its sole discretion (the "Title Policies"). Landlord agrees to cooperate fully and promptly with Tenant in its efforts to obtain the Title Policies, and Landlord shall take such actions as Tenant may reasonably request in connection therewith at no cost to Landlord. Landlord represents that (a) there are no pending or threatened claims, actions or suits affecting the Site or Landlord's interest in the Site or the Easement Areas; (b) the execution and performance of this Ground Lease by Landlord does not violate any contract, agreement or instrument to which Landlord is a party; (c) the execution, delivery and performance by it under this Ground Lease have been duly authorized by all necessary action by Landlord, and do not violate any provision of any current law applicable to Landlord, the Site or the Easement Areas or any order, judgment or decree of any court or other agency presently binding on Landlord or conflict with or result in a breach of or constitute a default under any contractual obligation of Landlord; and (d) this Ground Lease is the legally valid and binding obligation of Landlord enforceable against it in accordance with its terms except as enforcement may be limited by bankruptcy, insolvency, or reorganization, moratorium or similar laws or equitable principles relating or limiting creditors rights generally.

18.2 Environmental. Landlord represents that, to the best of Landlord's knowledge, as of the Effective Date (a) the Site and Easement Areas are free of known or identified Hazardous Materials, no Hazardous Materials have ever been produced or disposed upon the Site or the Easement Areas, no Release has occurred on the Site or the Easement Areas and Hazardous Materials have not migrated to the Site or the Easement Areas, (b) the Site and the Easement Areas and are in material compliance with all Environmental Laws, (c) neither the Site nor the Easement Areas are subject to any Environmental Liability, threatened Environmental Liability or alleged Environmental Liability, and (d) Landlord has not received notice of any violation of Environmental Laws affecting the Site or the Easement Areas.

18.3 Subordination Agreements. Landlord shall, at its expense, promptly remove, or cause to be subordinated to the Ground Lease all monetary obligations and any related liens that are described as exceptions to

the Title Policies. Any such subordination agreement shall be in a form as may be reasonably acceptable to Tenant, which provides, among other things, that Tenant's occupancy or use of the Site in accordance with the terms of this Ground Lease will not be disturbed so long as Tenant is not in default under the terms of this Ground Lease or the SSPA beyond any applicable notice and cure period.

19. Tenant's Representations, Warranties, and Covenants.

19.1 Authority; Enforceability. Tenant represents and warrants that (a) the execution and performance of this Ground Lease by Tenant does not violate any contract, agreement or instrument to which Tenant is a party; (b) the execution, delivery and performance by it under this Ground Lease have been duly authorized by all necessary action by Tenant, and do not violate any provision of any current law applicable to Tenant, the Site or the Easement Areas or any order, judgment or decree of any court or other agency presently binding on Tenant or conflict with or result in a breach of or constitute a default under any contractual obligation of Tenant; and (c) this Ground Lease is the legally valid and binding obligation of Tenant enforceable against it in accordance with its terms except as enforcement may be limited by bankruptcy, insolvency, or reorganization, moratorium or similar laws or equitable principles relating or limiting creditors rights generally.

19.2 Environmental. Tenant hereby covenants that Tenant and its agents, employees and contractors will not generate, store, use, treat or dispose of any Hazardous Materials in, on or at the Site or any part of the Facility, except for Hazardous Materials as are commonly legally used or stored (and in such amounts as are commonly legally used or stored) as a consequence of using the Facility for the permitted use hereunder, but only so long as the quantities thereof do not pose a threat to public health or to the environment or would necessitate a "response action", as that term is defined in CERCLA, and so long as Tenant strictly complies or causes compliance with all laws, statutes, rules, orders, regulations, ordinances and decrees concerning the use or storage of such Hazardous Substances. Tenant further covenants that neither the Site nor any part of the Facility shall ever be used by Tenant or its agents, contractors or employees as a dump site or storage site (whether permanent or temporary) for any Hazardous Substances during the Term.

20. Utilities. Tenant shall pay for all Utilities consumed by Tenant at the Site during the Term.

21. Taxes.

21.1 Covenant to Pay Taxes and Assessments. Tenant shall be responsible for and shall pay the Taxes and Assessments, if any, as hereinafter defined, which are imposed on the Site, the Facility or Tenant's operations at the Site. "Taxes and Assessments" shall mean all taxes, assessments or other impositions, general or special, ordinary or extraordinary, of every kind or nature, which may be levied, assessed or imposed upon or with respect to the Site, the Facility or Tenant's operations at the Site or any improvements, fixtures, equipment or personal property of Tenant at any time situated thereon, including, but not limited to, any ad valorem and inventory taxes. Landlord shall pay (i) any transfer or conveyance tax arising out of this Ground Lease, and (ii) all taxes and assessments regarding the Site, if any. Landlord shall also timely pay all taxes, assessments or other impositions which may be levied, assessed or imposed upon or with respect to the Easement Area(s) (and with respect to the Easement Areas regarding the Electrical Interconnection Easement, any buildings, improvements, fixtures, equipment or personal property situated thereon belonging to anyone other than Tenant), if any. Tenant shall not be responsible for the payment of any income or similar tax due and payable on Landlord's receipt of the rental payment under this Ground Lease or any taxes regarding the Site (other than as apportioned to the Facility equipment and property owned by Tenant) or Landlord's real property.

21.2 Tenant's Right to Contest Taxes. Without limiting the right of Landlord to contest any Taxes and Assessments levied against the Site, Tenant shall have the right to contest any Taxes or Assessments payable by Tenant, provided, Tenant shall, in good faith and with due diligence, contest the same or the validity thereof by appropriate legal proceedings which shall have the effect of preventing the collection of the tax or assessment and the sale or foreclosure of any lien for such tax or assessment. Tenant shall have the right, at its sole expense, to institute and prosecute, in Landlord's name, any suit or action to contest any tax or assessment payable by Tenant or to recover the amount of any such tax or assessment but, in such event, Tenant hereby covenants and agrees to indemnify and save Landlord harmless from any and all reasonable and documented costs and expenses, including attorneys' fees, in connection with any such suit or action. Any funds recovered by Tenant as a result of any such

suit or action shall belong to Tenant except to the extent any such recovery relates to a period of time that is not part of the Term. Any part of such recovery relating to a period not part of the Term shall be paid to Landlord.

22. Assignment.

22.1 Assignment by Landlord. Landlord may sell, assign or transfer all (but not less than all) of its interest in the Site or this Ground Lease at any time to a successor in interest (who must expressly assume the obligations of Landlord hereunder), and Landlord shall thereafter be released or discharged from all of its covenants and obligations hereunder, except such obligations as shall have accrued prior to any such sale, assignment or transfer, and Tenant agrees to look solely to such successor in interest of Landlord for performance of such obligations arising after such sale, transfer or assignment. In the event of such sale, assignment or transfer of its interest, Landlord shall promptly notify Tenant of same. Landlord shall also have the right to place a mortgage or deed of trust upon the Site, in which event this Ground Lease shall be subordinate to the lien of any deed of trust or mortgage, provided that the beneficiary of such deed of trust or mortgage shall agree in writing, that so long as Tenant is not in default under the terms of this Ground Lease beyond any applicable notice and cure period as set forth herein, such beneficiary shall not disturb Tenant's rights under this Ground Lease.

22.2 Assignment by Tenant. Tenant may not sell, assign, sublease, mortgage, pledge, or otherwise transfer its interest in the Site or this Ground Lease without the prior written consent of Landlord, which consent shall not be unreasonably withheld, conditioned or delayed. Notwithstanding the immediately preceding sentence, Tenant may, without the consent of Landlord, assign or sublease this Ground Lease to (a) any entity which controls, is controlled by or under common control with Tenant; (b) any entity resulting from the merger or consolidation of Tenant; (c) any person or entity which acquires all of the assets of Tenant as a going concern of the business that is being conducted on the Site, provided that said transferee assumes all of the obligations of Tenant under the Ground Lease; or (d) or , subject to the provisions of Article 17, any Financing Party in connection with the financing and/or construction of the Facility on the Site. Tenant shall remain liable for all obligations of Tenant under this Ground Lease in connection with any assignment or sublease of this Ground Lease unless, in the case of an assignment, such assignment is a part of a merger or other transaction in which all or substantially all of the assets of Tenant are acquired by the assignee or an affiliate of such assignee or if such assignee has a net worth at the time of the assignment of not less than $500,000,000.00.

23. Ownership of Electricity and Environmental Attributes And Incentives. Landlord and Tenant agree that Tenant (or its Affiliate) is the exclusive owner of electricity (kWh) generated by the Facility and the exclusive owner of any applicable Environmental Attributes of the Facility now or hereafter in effect (if any), and that Tenant shall have the exclusive right to any applicable proceeds related to the sale or other transfer of such electricity generated by the Facility as well as the right to report to any federal, state or local agency, authority or other party that Tenant or its Affiliate is the exclusive owner of any applicable Environmental Attributes and Environmental Incentives. As used herein, "Environmental Attributes" means the characteristics of electric power generation at the Facility that have intrinsic value, separate and apart from the energy output therefrom (the "Energy Output"), arising from the perceived environmental benefits of the Facility. Further, as used herein, "Environmental Incentives" means all rights, credits (including without limitation all tax credits, as above described), rebates, benefits, reductions, offsets, and allowances and entitlements of any kind, howsoever entitled or named (including carbon credits and allowances), whether arising under federal, state or local law, international treaty, trade association membership or the like, arising from the Environmental Attributes of the Facility or the energy output therefrom or otherwise from the development or installation of the Facility or the production, sale, purchase, consumption or use of the Energy Output.

24. Miscellaneous.

24.1 Notices. Any notice, consent or other formal communication required or permitted to be given by a Party pursuant to the terms of this Agreement shall be in writing and shall be deemed delivered (a) when delivered personally or by email, unless such delivery is made (i) on a day that is not a business day in the place of receipt or (ii) after 5:00 p.m. local time on a business day in the place of receipt, in either of which cases such delivery will be deemed to be made on the next succeeding business day, (b) on the next business day after timely delivery to a reputable overnight courier and (c) on the business day actually received if deposited in the U.S. mail (certified or registered mail, return receipt requested, postage prepaid), addressed as follows (or to such other address or having

such other contact information as either Party may hereafter specify for such purpose by like notice to the other Party from time to time):

(a) if to Tenant, addressed to:

Duke Energy Carolinas, LLC
400 South Tryon Street
Floor 14
Charlotte, NC 28202
Attention: Zachary Kuznar
Phone: (704) 382-9644
Email: zachary.kuznar@duke-energy.com

With a copy to:

Duke Energy Carolinas, LLC
Office of General Counsel
550 South Tryon Street DEC45A
Charlotte, NC 28202
Attention: Karol Mack
Phone: (704) 382-8165
Email: karol.mack@duke-energy.com

(b) if to Landlord, addressed to:

Clemson University
207 Sikes Hall
Clemson, SC 29634
Attention: General Counsel

with a copy to:

Nelson Mullins Riley & Scarborough LLP
Poinsett Plaza, Suite 900
104 South Main Street
Greenville, SC 29601
Attention: D. Sean Faulkner

or to such other address as either Party shall from time to time designate in writing to the other Party.

24.2 Counterparts; Signatures. This Ground Lease may be executed in counterparts. All executed counterparts shall constitute one agreement, and each counterpart shall be deemed an original. The parties hereby acknowledge and agree that facsimile signatures or signatures transmitted by electronic mail in so-called "pdf" format shall be legal and binding and shall have the same full force and effect as if an original of this Ground Lease had been delivered. Landlord and Tenant (i) intend to be bound by the signatures on any document sent by facsimile or electronic mail, (ii) are aware that the other party will rely on such signatures, and (iii) hereby waive any defenses to the enforcement of the terms of this Ground Lease based on the foregoing forms of signature.

24.3 Amendments. Neither this Ground Lease nor any of the terms hereof may be terminated, amended, supplemented, waived or modified orally, but only by an instrument in writing signed by the Party against which the enforcement of the termination, amendment, supplement, waiver or modification shall be sought.

24.4 Headings, etc. The headings of the various Articles and Sections of this Ground Lease are for convenience of reference only and shall not modify, define, expand or limit any of the terms or provisions hereof.

24.5 Successors and Assigns. The terms of this Ground Lease shall be binding upon, and inure to the benefit of, the Parties hereto and their respective successors and permitted assigns.

24.6 Confidentiality. Landlord and Tenant each agree to use commercially reasonable efforts to keep confidential, and not publicly disclose, the terms of this Ground Lease and any information provided by Landlord to Tenant or by Tenant to Landlord in relation to the transaction contemplated hereby; provided, however, that either Party may disclose the existence and terms of this Ground Lease to: (a) its consultants, agents, architects, independent contractors, or attorneys in connection with the execution of this Ground Lease, (b) any bona fide potential purchaser or lender of the Facility who agrees to keep such information confidential, (c) any third party to whom both Parties hereto have given their prior written consent for such a disclosure, or (d) governmental, administrative, regulatory or judicial authorities in the investigation of the compliance of the Site, the Facility and/or the Easement Areas with applicable legal requirements; and provided, further, that the non-disclosure obligations contained in this Section shall not apply to any such information that (i) is or becomes generally available to the public other than as a result of a disclosure by Tenant or Landlord, or their employees, agents or representatives, or (ii) Landlord or Tenant is compelled to disclose pursuant to any judicial, statutory or regulatory authority. The provisions of this Section shall survive the termination of this Ground Lease. The confidentiality requirements of this Ground Lease will not apply to confidential information to the extent that the Landlord is required to disclose such confidential information pursuant to applicable law or legal process, including the South Carolina Freedom of Information Act.

24.7 Interpretation. The Parties acknowledge that this Ground Lease, as executed, is the product of negotiations between Landlord and Tenant and that it shall be construed fairly, in accordance with its terms, and shall not be construed for or against either Party. No inferences as to the intention of the Parties shall arise from the deletion of any language or provisions of this Ground Lease.

24.8 Memorandum of Lease. Concurrently with the execution of this Ground Lease, Landlord and Tenant shall execute, acknowledge before a notary public, in recordable form, and deliver a short form memorandum of lease which shall be recorded by Tenant in the Official Records.

24.9 Severability. If any term or provision of this Ground Lease is, to any extent, determined by a court of competent jurisdiction to be invalid or unenforceable, the remainder of this Ground Lease shall not be affected thereby, and each remaining term and provision of this Ground Lease shall be valid and enforceable to the fullest extent permitted by law.

24.10 Time is of the Essence. Time is of the essence of this Ground Lease and each and every provision of this Ground Lease.

24.11 Consent and Approvals. Any consent or approval that a Party is obligated to give to the other Party shall not be unreasonably withheld or delayed, subject to any specific provision to the contrary contained in this Ground Lease.

24.12 Entire Agreement. This Ground Lease, including any exhibits and attachments hereto, constitutes the entire agreement between Landlord and Tenant relative to the matters and transactions contemplated herein. Landlord and Tenant agree hereby that all prior or contemporaneous oral or written agreements, or letters of intent, between and among themselves or their agents including any leasing agents and representative, relative to such matters and transactions are merged in or revoked by this Ground Lease.

24.13 Broker's Commission. Tenant represents and warrants that it has not dealt with any broker or agent in connection with this Ground Lease and Tenant agrees to indemnify and save Landlord harmless from any claims made by any brokers or agents claiming to have dealt with Tenant. Landlord represents and warrants that it has not dealt with any brokers or agents in connection with this Ground Lease, and Landlord agrees to indemnify and save Tenant harmless from any claims made by any brokers or agents claiming to have dealt with Landlord. The terms and provisions of this Section shall survive the termination or earlier expiration of this Ground Lease.

24.14 WAIVER OF JURY TRIAL. TO THE EXTENT PERMITTED BY LAW, THE PARTIES HEREBY WAIVE ANY AND ALL RIGHTS THAT THEY MAY NOW OR HEREAFTER HAVE UNDER THE LAWS OF THE UNITED STATES OF AMERICA OR ANY STATE, TO A TRIAL BY JURY OF ANY AND ALL ISSUES ARISING DIRECTLY OR INDIRECTLY IN ANY ACTION OR PROCEEDING RELATING TO THIS GROUND LEASE OR ANY TRANSACTIONS CONTEMPLATED HEREBY OR RELATED HERETO. IT IS INTENDED THAT THIS WAIVER SHALL APPLY TO ANY AND ALL CAUSES OF ACTION, DEFENSES, RIGHTS, CLAIMS AND/OR COUNTERCLAIMS, WHETHER IN CONTRACT, TORT OR OTHERWISE, IN ANY SUCH ACTION OR PROCEEDING. THE PARTIES UNDERSTAND THAT THIS WAIVER IS A WAIVER OF A CONSTITUTIONAL SAFEGUARD, AND THE PARTIES BELIEVE THAT THERE ARE SUFFICIENT ALTERNATE PROCEDURAL AND SUBSTANTIVE SAFEGUARDS, INCLUDING A TRIAL BY AN IMPARTIAL JUDGE, THAT ADEQUATELY OFFSET THE WAIVER CONTAINED HEREIN.

24.15 EXCULPATION. TENANT AGREES THAT TENANT SHALL LOOK SOLELY TO LANDLORD'S INTEREST IN THE SITE AND INSURANCE, CONDEMNATION AND SALES PROCEEDS THEREFROM OR LANDLORD'S PERSONAL PROPERTY USED IN CONNECTION THEREWITH FOR THE SATISFACTION OF ANY CLAIM, JUDGMENT OR DECREE REQUIRING THE PAYMENT OF MONEY BY LANDLORD BASED UPON ANY UNCURED DEFAULT BY LANDLORD HEREUNDER, AND NO OTHER PROPERTY OR ASSETS OF LANDLORD, ITS SUCCESSORS OR ASSIGNS, SHALL BE SUBJECT TO LEVY, EXECUTION OR OTHER ENFORCEMENT PROCEDURE FOR THE SATISFACTION OF ANY SUCH CLAIM, JUDGMENT, INJUNCTION OR DECREE.

24.16 Conflicts with SSPA. To the extent any of the provisions of this Ground Lease expressly conflict with the provisions of the SSPA, the terms and conditions of the SSPA shall control.

[Signatures Begin on Next Page]

IN WITNESS WHEREOF, the parties hereto have caused this Ground Lease to be duly executed by their respective officers thereto duly authorized as of the day and year first above written.

LANDLORD:

Clemson University,
a body politic under the laws of the State of South Carolina

By: Brett A. Dalton
Name: Brett A. Dalton
Title: Executive Vice President of Finance & operations

STATE OF S.C.

COUNTY OF Pickens

The foregoing instrument was acknowledged before me this 2 day of Feb, 2017, by Brett Dalton, EVP of Clemson Univ, a body politic under the laws of SC.

W C Hood Jr
Notary Public
Printed Name of Notary: W C Hood Jr
My Commission Expires: JAN 10, 2022

TENANT:

Duke Energy Carolinas, LLC

By: Robert F. Caldwell
Name: Robert F. Caldwell
Title: President

STATE OF North Carolina

COUNTY OF Mecklenburg

The foregoing instrument was acknowledged before me this 10th day of January, 2017, by Robert F. Caldwell, President of Duke Energy Carolinas LLC a _____.

Andrea K. Bizzell
Notary Public
Printed Name of Notary: Andrea K. Bizzell
My Commission Expires: June 25, 2017

Andrea K. Bizzell NOTARY My Comm. Exp. June 25 2017 PUBLIC Iredell County, NC

EXHIBIT A
to Ground Lease

Location and Description of the Site

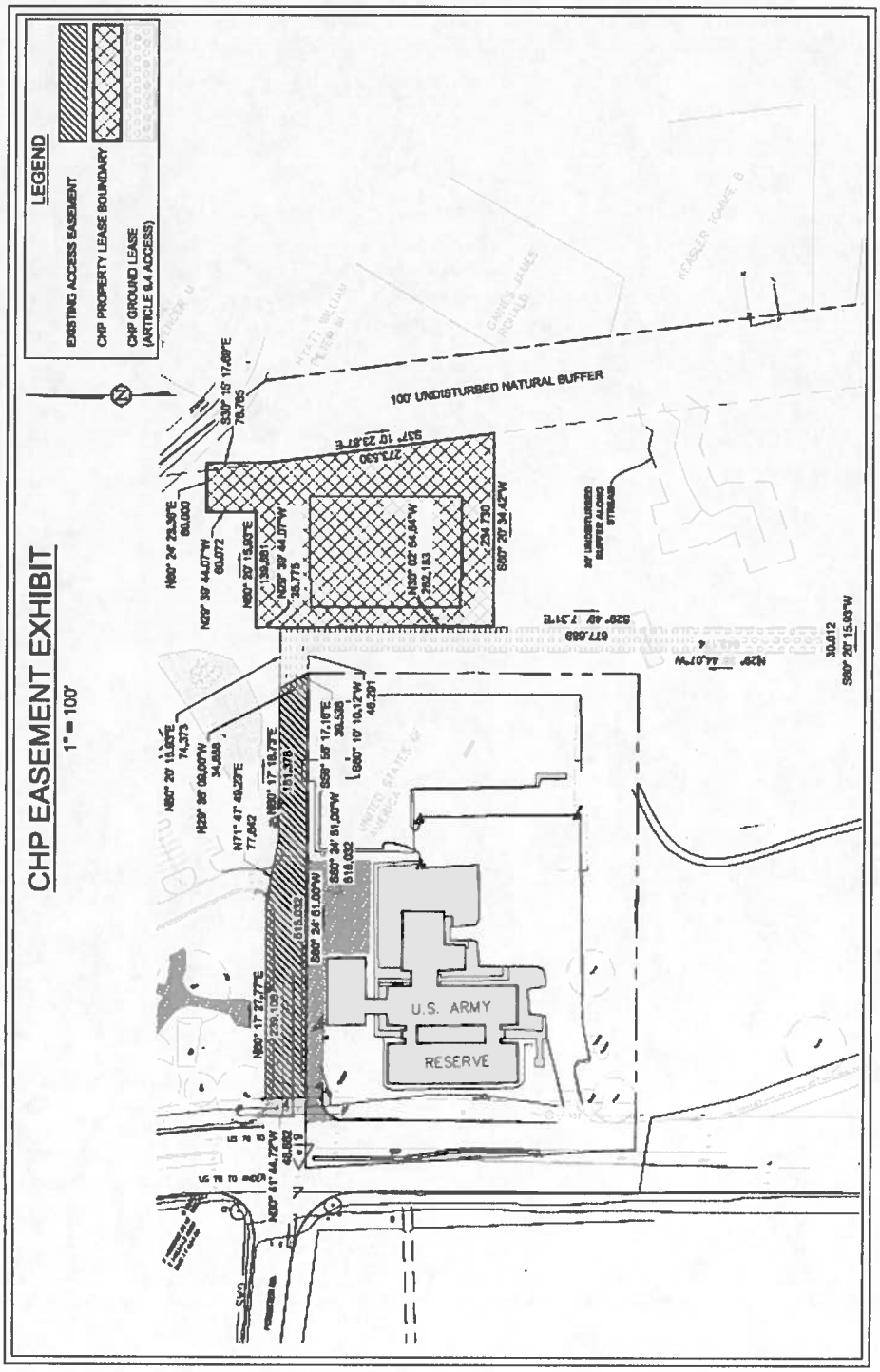

EXHIBIT B
to Ground Lease

Definitions

1. "Affiliate" means, when used with reference to a specified Person, any other Person that directly, or indirectly through one or more intermediaries, controls, is controlled by or is under common control with the Person specified.

2. "Business Day" means any day other than Saturday or Sunday or a legal holiday observed by the State of South Carolina.

3. "Casualty" means any loss or destruction of or damages to the Facility or the Site resulting from any act of God, fire, explosion, earthquake, accident or the elements, whether or not covered by insurance and whether or not caused by the fault or negligence of either Party, or such Party's employees, agents, contractors, or visitors.

4. "Commercial Operation Date" means the date upon which Tenant notifies Landlord that the Facility is commercially operational.

5. "Development Period" means the period during which Tenant performs development activities, including but not limited to, obtaining permits and constructing the Facility, as more particularly defined in Section 2.1.1.

6. "Easements" has the meaning set forth in Section 5.

7. "Easement Areas" has the meaning set forth in Section 5.

8. "Effective Date" has the meaning set forth in the Preamble.

9. "Electrical Interconnection Easement" has the meaning set forth in Section 5.

10. "Energy Output" has the meaning set forth in Section 24.

11. "Environmental Attributes" has the meaning set forth in Section 24.

12. "Environmental Incentives" has the meaning set forth in Section 24.

13. "Environmental Laws" means any federal, state or local law, code, statute, ordinance, rule, regulation, rule of common law, guideline or informal policy position, relating to or imposing liability or standards of conduct concerning any hazardous, toxic or dangerous waste, substance or material; or any substances or mixture of any Hazardous Materials regulated thereunder, now or hereafter enacted or promulgated (collectively, and including, without limitation, any such laws which require notice of the use, presence, storage, generation, disposal or release of any Hazardous Materials to be provided to any party).

14. "Environmental Liability" means any action, lawsuit, claim or proceeding arising under or related in any way to the Environmental Laws or which seeks to impose liability for (a) noise; (b) pollution or contamination of the air, surface water, ground water or land or the clean-up of such pollution or contamination; (c) solid, gaseous or liquid waste generation, handling, treatment, storage, disposal or transportation; (d) exposure to or contamination by Hazardous Materials; (e) the safety or health of employees or (f) the manufacture, processing, distribution in commerce or use of Hazardous Materials. An "Environmental Liability" includes a common law action, whether direct or indirect, as well as a proceeding to issue, modify or terminate an Environmental Permit, or to adopt or amend a regulation to the extent that such a proceeding attempts to redress violations of an applicable permit, license, or regulation as alleged by any governmental authority.

15. "Environmental Permit" means any permit, license, approval or other authorization under any applicable Environmental Laws.

16. "Facility" means a combined heat and power facility or facilities and related utilities, improvements, equipment, facilities, appurtenances and other improvements to be developed, constructed, owned, operated and maintained on the Site and any applicable Easement Area(s), including but not limited to all structures, machinery, equipment, meters, fixtures, interconnections, ancillary equipment and materials, and all additions, alterations, expansions and modifications thereto as may be located on the Site and the Easement Areas.

17. "Financing Parties" has the meaning set forth in Section 17.

18. "Financing Documents" has the meaning set forth in Section 17.

19. "Force Majeure" means all events beyond the control of the Party affected, including without limitation flood, earthquake, storm, lightning, fire, explosion, war, riot, civil disturbances, strikes, and sabotage.

20. "Governmental Approvals" has the meaning set forth in Section 9.2(c).

21. "Ground Lease" has the meaning set forth in the Preamble.

22. "Hazardous Materials" means any flammable, reactive, explosive, corrosive or radioactive materials or hazardous, toxic or dangerous wastes, substances or related materials or any other chemicals, materials, wastes or substances, exposure to which is prohibited, limited or regulated by a federal, state, county, regional or local authority, or any Environmental Laws.

23. "Official Records" means the Official Records maintained by the office of the Register of Deeds of Pickens County, South Carolina.

24. "Operational Easements" has the meaning set forth in Section 5.

25. "Operational Term" means the period during which the Facility is generating and delivering Steam as such term(s) are defined in the SSPA, commencing upon the Commercial Operation Date for the Facility and terminating upon expiration or earlier termination as provided herein in Section 2.1.2.

26. "Landlord" has the meaning set forth in the Preamble.

27. "Landlord Easements" has the meaning set forth in Section 5.

28. "Landlord Events of Default" has the meaning set forth in Section 13.3.

29. "Landlord's Property" means all premises other than the Site and Easement Areas that are owned or leased by Landlord or its Affiliates and at which the Steam will be used or through which the Steam will be delivered.

30. "Landlord's Parties" means Landlord, its officers, directors, partners, members, affiliates, lenders, employees, shareholders, attorneys, lessees (other than Tenant), sublessees, licensees, invitees, contractors, subcontractors, consultants, agents, trustees and any of their respective successors and assigns.

31. "Landlord Utilities" has the meaning set forth in Section 5.

32. "Losses" has the meaning set forth in Section 12.1(a).

33. "Manual" has the meaning set forth in Section 9.2(b).

34. "OSE" has the meaning set forth in Section 9.2(b).

35. "Party" or "Parties" means Landlord and/or Tenant, as applicable.

36. "Permitted Exceptions" has the meaning set forth in Section 18.1.

37. "Person" means any individual, corporation, partnership, limited liability company, joint venture, association, joint stock company, trust, estate, unincorporated organization or other business entity, or any governmental authority.

38. "Release" means any release, pumping, pouring, emptying, injecting, escaping, leaching, dumping, seepage, spill, leak, flow, discharge, disposal or emission of a Hazardous Material whether on, under or migrating to or from the property of any Party.

39. "Site" means that certain land located in Pickens County, South Carolina, as more particularly shown and described on Exhibit A attached hereto.

40. "SSPA" means that certain Steam Supply and Purchase Agreement dated Febrny 2, 2017 between Tenant, as "Seller", and Landlord, as "Buyer."

41. "State" has the meaning set forth in Section 10.1(b).

42. "Tenant" has the meaning set forth in the Preamble.

43. "Tenant Events of Default" has the meaning set forth in Section 13.1.

44. "Tenant's Force Majeure Notice" has the meaning set forth in Section 2.2.1.

45. "Tenant's Force Majeure Termination Notice" has the meaning set forth in Section 2.2.1.

46. "Tenant's Parties" means Tenant, its officers, directors, partners, members, affiliates, lenders, employees, shareholders, attorneys, lessees, sublessees, licensees, invitees, contractors, subcontractors, consultants, agents and any of their respective successors and assigns.

47. "Term" has the meaning set forth in Section 2.1.2.

48. "Title Policies" has the meaning set forth in Section 18.1.

49. "Transfer" means a transfer or conveyance of Landlord's interest in (i) the Site, (ii) the Easements and/or (iii) this Ground Lease.

50. "Utilities" means the services and related improvements, equipment and facilities necessary for the operation of the Facility, including, but not limited to, natural gas, electrical power, water, storm water, sanitary sewer, roads, telephone and telecommunication services, improvements, equipment and facilities.

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Feb 18 2020

Public Staff
Saillor Exhibit 1

Docket No. E-7, Sub 1214

Calculation of Weather Normalization Revenue Adjustment

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	(521,492,469)	8.46	$ (44,128)
General	(731,235,106)	6.70	(48,959)
Industrial	(69,106,813)	5.58	(3,857)
Total NC Retail	(1,321,834,388)		$ (96,944)

Note 1: Average customer class rates are based on annualized revenues divided by per book sales. Annualized revenues do not include basic facilities charges.

Note 2: Dollars in thousands.

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Feb 18 2020

Public Staff
Saillor Exhibit 2

Docket No. E-7, Sub 1214

Monthly NC Retail kWh Weather Adjustments updated through November 2019

North Carolina* Weather Adjustments

Line No.	Month	Year	Residential	General Service	Industrial
1	Jan	2018	(163,690,037)	(139,255,580)	-
2	Feb	2018	153,105,293	(1,890,072)	(760,848)
3	Mar	2018	389,926,377	-	-
4	Apr	2018	(51,747,444)	(12,910,346)	23,832,061
5	May	2018	4,590,698	(8,265,717)	1,947,340
6	Jun	2018	(255,219,789)	(152,442,084)	(61,615,343)
7	Jul	2018	(168,863,055)	(88,284,807)	(20,664,248)
8	Aug	2018	37,845,731	20,993,498	7,300,144
9	Sep	2018	(94,956,283)	(424,567,999)	(286,567,931)
10	Oct	2018	(209,085,315)	100,787,321	270,097,024
11	Nov	2018	(9,330,196)	(2,323,726)	(2,675,012)
12	Dec	2018	(154,068,450)	(23,075,594)	-
13	Total		(521,492,469)	(731,235,106)	(69,106,813)

*Values were generated using the monthly historical ratio of NC actual billed sales to actual billed sales (NC/System)

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Feb 18 2020

Public Staff
Saillor Exhibit 3

Docket No. E-7, Sub 1214

Customer Growth and Change in Usage Adjustment through November 30, 2019

Rate Class (a)	Per Books kWh Sales (b)	Change in # of Bills[1] (c)	Nov 2019 EOP Level of Customers (d)	Customer Growth Adjustment (e)	Change in Usage Adjustment (f)	Adjusted Per Books kWh Sales (g)
Residential	22,763,028,911	577,106	1,767,807	631,330,612	(517,967,451)	22,876,392,072
General	23,453,934,649	7,846		139,047,701	11,437,830	23,604,420,180
BC	16,159,670	3,967	8,014	827,864	(1,061,362)	15,926,172
Lighting	681,748,328	18,574	286,672	3,697,119	-	685,445,447
TS	10,081,816	687	5,971	102,928	(490,705)	9,694,039
Industrial	12,555,749,214	(238)		127,254,164	34,703,250	12,717,706,628
Total NC Retail	59,480,702,588			902,260,388	(473,378,438)	59,909,584,537

Note 1: For the General and Industrial customer classes, the change in the number of bills equals the number of bills added for new accounts minus the number of bills removed for closed accounts.

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Feb 18 2020

Public Staff
Saillor Exhibit 4

Docket No. E-7, Sub 1214

Calculation of Customer Growth Revenue Adjustment

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	631,330,612	9.75	$ 61,580
General	139,047,701	6.96	9,684
BC	827,864	15.68	130
Lighting	3,697,119	17.35	642
TS	102,928	16.92	17
Industrial	127,254,164	5.59	7,116
Total NC Retail	902,260,388		$ 79,168

Note 1: Average customer class rates are based on annualized revenues divided by per book sales.

Note 2: Dollars in thousands.

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Feb 18 2020

Public Staff
Saillor Exhibit 5

Docket No. E-7, Sub 1214

Calculation of Change in Usage Revenue Adjustment

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	(517,967,451)	8.46	$ (43,829)
General	11,437,830	6.70	766
BC	(1,061,362)	5.44	(58)
Lighting	-		-
TS	(490,705)	12.21	(60)
Industrial	34,703,250	5.58	1,937
Total NC Retail	(473,378,438)		$ (41,244)

Note 1: Average customer class rates are based on annualized revenues divided by per book sales. Annualized revenues do not include basic facilities charges.

Note 2: Dollars in thousands.

Public Staff
Saillor Exhibit 1

Docket No. E-7, Sub 1214

Calculation of Weather Normalization Revenue Adjustment
(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment[2] (d) = (b) × (c) ÷ 100,000
Residential	(521,492,469)	8.46	$ (44,129)
General	(728,915,472)	6.70	(48,808)
Industrial	(69,374,972)	5.58	(3,872)
Total NC Retail	(1,319,782,913)		$ (96,809)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.

Public Staff
Saillor Exhibit 2

Docket No. E-7, Sub 1214

Monthly NC Retail kWh Weather Adjustments updated through January 2020

North Carolina* Weather Adjustments

Line No.	Month	Year	Residential	General Service	Industrial
1	Jan	2018	(163,690,037)	(136,665,114)	-
2	Feb	2018	153,105,293	(1,884,298)	(770,362)
3	Mar	2018	389,926,377	-	-
4	Apr	2018	(51,747,444)	(12,842,604)	24,037,690
5	May	2018	4,590,698	(8,235,775)	1,960,180
6	Jun	2018	(255,219,789)	(152,295,127)	(61,830,494)
7	Jul	2018	(168,863,055)	(88,220,793)	(20,759,078)
8	Aug	2018	37,845,731	20,978,838	7,320,935
9	Sep	2018	(94,956,283)	(424,340,794)	(286,617,319)
10	Oct	2018	(209,085,315)	101,033,137	269,978,927
11	Nov	2018	(9,330,196)	(2,313,207)	(2,695,452)
12	Dec	2018	(154,068,450)	(24,129,735)	-
13	Total		(521,492,469)	(728,915,472)	(69,374,972)

*Values were generated using the monthly historical ratio of NC actual billed sales to actual billed sales (NC/System)

Public Staff
Saillor Exhibit 3

Docket No. E-7, Sub 1214

Customer Growth and Change in Usage kWh Adjustments through January 31, 2020

Rate Class	Test Year Number of Bills	Number of Bills at End of Period	Change in # of Bills[1]	Customer Growth kWh Adjustment	Change in Usage kWh Adjustment
Residential	20,636,578	21,248,772	612,194	669,161,324	(479,868,101)
General	3,127,951	3,138,828	10,877	137,235,271	44,279,353
BC	92,201	92,268	67	139,189	(934,567)
Lighting	3,421,490	3,438,204	16,714	3,326,514	-
TS	70,965	71,784	819	121,672	(518,384)
Industrial	57,951	57,638	(313)	147,082,334	57,644,137
Total NC Retail				957,066,303	(379,397,562)

Note 1: For the General and Industrial customer classes, the change in the number of bills equals the number of bills added for new accounts minus the number of bills removed for closed accounts.

Public Staff
Saillor Exhibit 4

Docket No. E-7, Sub 1214

Calculation of Customer Growth Revenue Adjustment
(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	BFC Revenues[2] (d)	Revenue Adjustment (e) = (b) × (c) ÷ 100,000 + (d)
Residential	669,161,324	8.46	$ 8,571	$ 65,195
General	137,235,271	6.96		9,558
BC	139,189	15.68		22
Lighting	3,326,514	17.35		577
TS	121,672	16.92		21
Industrial	147,082,334	5.59		8,224
Total NC Retail	957,066,303			$ 83,597

Note 1: Average customer class rates are based on annualized revenues divided by per book sales.

Note 2: For Residential customers, revenues from Basic Facilities Charges are calculated separately.

Public Staff
Saillor Exhibit 5

Docket No. E-7, Sub 1214

Calculation of Change in Usage Revenue Adjustment
(Dollars in thousands)

Rate Class (a)	NC Retail kWh Adjustment (b)	Cents Per kWh[1] (c)	Revenue Adjustment (d) = (b) × (c) ÷ 100,000
Residential	(479,868,101)	8.46	$ (40,606)
General (OPT only)	183,643,203	5.75	10,564
General (non-OPT only)	(139,363,851)	8.01	(11,167)
BC	(934,567)	5.95	(56)
Lighting	-		-
TS	(518,384)	12.21	(63)
Industrial (OPT only)	39,988,349	5.27	2,109
Industrial (non-OPT only)	17,655,788	7.10	1,254
Total NC Retail	(397,053,351)		$ (37,965)

Note 1: Average customer class rates are based on annualized revenues, excluding revenues from basic facilities charges, divided by per book sales.