ATTACHMENT 4

[Initial Comments of NC WARN and CBD]

Docket No. E-100, Sub 165

THIS FILING IS	
Item 1: [X] An Initial (Original) Submission	OR [ ] Resubmission No. ____

Form 1 Approved
OMB No.1902-0021
(Expires 11/30/2022)
Form 1-F Approved
OMB No.1902-0029
(Expires 11/30/2022)
Form 3-Q Approved
OMB No.1902-0205
(Expires 11/30/2022)

FERC FINANCIAL REPORT
FERC FORM No. 1: Annual Report of Major Electric Utilities, Licensees and Others and Supplemental Form 3-Q: Quarterly Financial Report

These reports are mandatory under the Federal Power Act, Sections 3, 4(a), 304 and 309, and 18 CFR 141.1 and 141.400. Failure to report may result in criminal fines, civil penalties and other sanctions as provided by law. The Federal Energy Regulatory Commission does not consider these reports to be of confidential nature

Exact Legal Name of Respondent (Company)	Year/Period of Report
Duke Energy Carolinas, LLC	End of 2019/Q4

INSTRUCTIONS FOR FILING FERC FORM NOS. 1 and 3-Q

GENERAL INFORMATION

I. Purpose

FERC Form No. 1 (FERC Form 1) is an annual regulatory requirement for Major electric utilities, licensees and others (18 C.F.R. § 141.1). FERC Form No. 3-Q (FERC Form 3-Q)is a quarterly regulatory requirement which supplements the annual financial reporting requirement (18 C.F.R. § 141.400). These reports are designed to collect financial and operational information from electric utilities, licensees and others subject to the jurisdiction of the Federal Energy Regulatory Commission. These reports are also considered to be non-confidential public use forms.

II. Who Must Submit

Each Major electric utility, licensee, or other, as classified in the Commission's Uniform System of Accounts Prescribed for Public Utilities and Licensees Subject To the Provisions of The Federal Power Act (18 C.F.R. Part 101), must submit FERC Form 1 (18 C.F.R. § 141.1), and FERC Form 3-Q (18 C.F.R. § 141.400).

Note: Major means having, in each of the three previous calendar years, sales or transmission service that exceeds one of the following:

(1) one million megawatt hours of total annual sales,
(2) 100 megawatt hours of annual sales for resale,
(3) 500 megawatt hours of annual power exchanges delivered, or
(4) 500 megawatt hours of annual wheeling for others (deliveries plus losses).

III. What and Where to Submit

(a) Submit FERC Forms 1 and 3-Q electronically through the forms submission software. Retain one copy of each report for your files. Any electronic submission must be created by using the forms submission software provided free by the Commission at its web site: http://www.ferc.gov/docs-filing/forms/form-1/elec-subm-soft.asp. The software is used to submit the electronic filing to the Commission via the Internet.

(b) The Corporate Officer Certification must be submitted electronically as part of the FERC Forms 1 and 3-Q filings.

(c) Submit immediately upon publication, by either eFiling or mail, two (2) copies to the Secretary of the Commission, the latest Annual Report to Stockholders. Unless eFiling the Annual Report to Stockholders, mail the stockholders report to the Secretary of the Commission at:

Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

(d) For the CPA Certification Statement, submit within 30 days after filing the FERC Form 1, a letter or report (not applicable to filers classified as Class C or Class D prior to January 1, 1984). The CPA Certification Statement can be either eFiled or mailed to the Secretary of the Commission at the address above.

The CPA Certification Statement should:

a) Attest to the conformity, in all material aspects, of the below listed (schedules and pages) with the Commission's applicable Uniform System of Accounts (including applicable notes relating thereto and the Chief Accountant's published accounting releases), and

b) Be signed by independent certified public accountants or an independent licensed public accountant certified or licensed by a regulatory authority of a State or other political subdivision of the U. S. (See 18 C.F.R. §§ 41.10-41.12 for specific qualifications.)

Reference Schedules	Pages
Comparative Balance Sheet	110-113
Statement of Income	114-117
Statement of Retained Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

e) The following format must be used for the CPA Certification Statement unless unusual circumstances or conditions, explained in the letter or report, demand that it be varied. Insert parenthetical phrases only when exceptions are reported.

"In connection with our regular examination of the financial statements of _____ for the year ended on which we have reported separately under date of _____ , we have also reviewed schedules _____of FERC Form No. 1 for the year filed with the Federal Energy Regulatory Commission, for conformity in all material respects with the requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases. Our review for this purpose included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

Based on our review, in our opinion the accompanying schedules identified in the preceding paragraph (except as noted below) conform in all material respects with the accounting requirements of the Federal Energy Regulatory Commission as set forth in its applicable Uniform System of Accounts and published accounting releases."

The letter or report must state which, if any, of the pages above do not conform to the Commission's requirements. Describe the discrepancies that exist.

(f) Filers are encouraged to file their Annual Report to Stockholders, and the CPA Certification Statement using eFiling. To further that effort, new selections, "Annual Report to Stockholders," and "CPA Certification Statement" have been added to the dropdown "pick list" from which companies must choose when eFiling. Further instructions are found on the Commission's website at http://www.ferc.gov/help/how-to.asp.

(g) Federal, State and Local Governments and other authorized users may obtain additional blank copies of FERC Form 1 and 3-Q free of charge from http://www.ferc.gov/docs-filing/forms/form-1/form-1.pdf and http://www.ferc.gov/docs-filing/forms.asp#3Q-gas .

IV. When to Submit:

FERC Forms 1 and 3-Q must be filed by the following schedule:

a) FERC Form 1 for each year ending December 31 must be filed by April 18th of the following year (18 CFR § 141.1), and

b) FERC Form 3-Q for each calendar quarter must be filed within 60 days after the reporting quarter (18 C.F.R. § 141.400).

V. Where to Send Comments on Public Reporting Burden.

The public reporting burden for the FERC Form 1 collection of information is estimated to average 1,168 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data-needed, and completing and reviewing the collection of information. The public reporting burden for the FERC Form 3-Q collection of information is estimated to average 168 hours per response.

Send comments regarding these burden estimates or any aspect of these collections of information, including suggestions for reducing burden, to the Federal Energy Regulatory Commission, 888 First Street NE, Washington, DC 20426 (Attention: Information Clearance Officer); and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503 (Attention: Desk Officer for the Federal Energy Regulatory Commission). No person shall be subject to any penalty if any collection of information does not display a valid control number (44 U.S.C. § 3512 (a)).

GENERAL INSTRUCTIONS

I. Prepare this report in conformity with the Uniform System of Accounts (18 CFR Part 101) (USofA). Interpret all accounting words and phrases in accordance with the USofA.

II. Enter in whole numbers (dollars or MWH) only, except where otherwise noted. (Enter cents for averages and figures per unit where cents are important. The truncating of cents is allowed except on the four basic financial statements where rounding is required.) The amounts shown on all supporting pages must agree with the amounts entered on the statements that they support. When applying thresholds to determine significance for reporting purposes, use for balance sheet accounts the balances at the end of the current reporting period, and use for statement of income accounts the current year's year to date amounts.

III Complete each question fully and accurately, even if it has been answered in a previous report. Enter the word "None" where it truly and completely states the fact.

IV. For any page(s) that is not applicable to the respondent, omit the page(s) and enter "NA," "NONE," or "Not Applicable" in column (d) on the List of Schedules, pages 2 and 3.

V. Enter the month, day, and year for all dates. Use customary abbreviations. **The "Date of Report" included in the header of each page is to be completed only for resubmissions** (see VII. below).

VI. Generally, except for certain schedules, all numbers, whether they are expected to be debits or credits, must be reported as positive. Numbers having a sign that is different from the expected sign must be reported by enclosing the numbers in parentheses.

VII For any resubmissions, submit the electronic filing using the form submission software only. Please explain the reason for the resubmission in a footnote to the data field.

VIII. Do not make references to reports of previous periods/years or to other reports in lieu of required entries, except as specifically authorized.

IX. Wherever (schedule) pages refer to figures from a previous period/year, the figures reported must be based upon those shown by the report of the previous period/year, or an appropriate explanation given as to why the different figures were used.

Definitions for statistical classifications used for completing schedules for transmission system reporting are as follows:

FNS - Firm Network Transmission Service for Self. "Firm" means service that can not be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff. "Self" means the respondent.

FNO - Firm Network Service for Others. "Firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Network Service" is Network Transmission Service as described in Order No. 888 and the Open Access Transmission Tariff.

LFP - for Long-Term Firm Point-to-Point Transmission Reservations. "Long-Term" means one year or longer and" firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. "Point-to-Point Transmission Reservations" are described in Order No. 888 and the Open Access Transmission Tariff. For all transactions identified as LFP, provide in a footnote the

termination date of the contract defined as the earliest date either buyer or seller can unilaterally cancel the contract.

OLF - Other Long-Term Firm Transmission Service. Report service provided under contracts which do not conform to the terms of the Open Access Transmission Tariff. "Long-Term" means one year or longer and “firm” means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions. For all transactions identified as OLF, provide in a footnote the termination date of the contract defined as the earliest date either buyer or seller can unilaterally get out of the contract.

SFP - Short-Term Firm Point-to-Point Transmission Reservations. Use this classification for all firm point-to-point transmission reservations, where the duration of each period of reservation is less than one-year.

NF - Non-Firm Transmission Service, where firm means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions.

OS - Other Transmission Service. Use this classification only for those services which can not be placed in the above-mentioned classifications, such as all other service regardless of the length of the contract and service FERC Form. Describe the type of service in a footnote for each entry.

AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment.

DEFINITIONS

I. Commission Authorization (Comm. Auth.) -- The authorization of the Federal Energy Regulatory Commission, or any other Commission. Name the commission whose authorization was obtained and give date of the authorization.

II. Respondent -- The person, corporation, licensee, agency, authority, or other Legal entity or instrumentality in whose behalf the report is made.

EXCERPTS FROM THE LAW

Federal Power Act, 16 U.S.C. § 791a-825r

Sec. 3. The words defined in this section shall have the following meanings for purposes of this Act, to with:

(3) ’Corporation' means any corporation, joint-stock company, partnership, association, business trust, organized group of persons, whether incorporated or not, or a receiver or receivers, trustee or trustees of any of the foregoing. It shall not include 'municipalities, as hereinafter defined;

(4) 'Person' means an individual or a corporation;

(5) 'Licensee, means any person, State, or municipality Licensed under the provisions of section 4 of this Act, and any assignee or successor in interest thereof;

(7) 'municipality means a city, county, irrigation district, drainage district, or other political subdivision or agency of a State competent under the Laws thereof to carry and the business of developing, transmitting, unitizing, or distributing power; .....

(11) "project' means. a complete unit of improvement or development, consisting of a power house, all water conduits, all dams and appurtenant works and structures (including navigation structures) which are a part of said unit, and all storage, diverting, or fore bay reservoirs directly connected therewith, the primary line or lines transmitting power there from to the point of junction with the distribution system or with the interconnected primary transmission system, all miscellaneous structures used and useful in connection with said unit or any part thereof, and all water rights, rights-of-way, ditches, dams, reservoirs, Lands, or interest in Lands the use and occupancy of which are necessary or appropriate in the maintenance and operation of such unit;

"Sec. 4. The Commission is hereby authorized and empowered

(a) To make investigations and to collect and record data concerning the utilization of the water 'resources of any region to be developed, the water-power industry and its relation to other industries and to interstate or foreign commerce, and concerning the location, capacity, development -costs, and relation to markets of power sites; ... to the extent the Commission may deem necessary or useful for the purposes of this Act."

"Sec. 304. (a) Every Licensee and every public utility shall file with the Commission such annual and other periodic or special* reports as the Commission may be rules and regulations or other prescribe as necessary or appropriate to assist the Commission in the -proper administration of this Act. The Commission may prescribe the manner and FERC Form in which such reports salt be made, and require from such persons specific answers to all questions upon which the Commission may need information. The Commission may require that such reports shall include, among other things, full information as to assets and Liabilities, capitalization, net investment, and reduction thereof, gross receipts, interest due and paid, depreciation, and other reserves, cost of project and other facilities, cost of maintenance and operation of the project and other facilities, cost of renewals and replacement of the project works and other facilities, depreciation, generation, transmission, distribution, delivery, use, and sale of electric energy. The Commission may require any such person to make adequate provision for currently determining such costs and other facts. Such reports shall be made under oath unless the Commission otherwise specifies*.10

"Sec. 309. The Commission shall have power to perform any and all acts, and to prescribe, issue, make, and rescind such orders, rules and regulations as it may find necessary or appropriate to carry out the provisions of this Act. Among other things, such rules and regulations may define accounting, technical, and trade terms used in this Act; and may prescribe the FERC Form or FERC Forms of all statements, declarations, applications, and reports to be filed with the Commission, the information which they shall contain, and the time within which they shall be field..."

General Penalties

The Commission may assess up to $1 million per day per violation of its rules and regulations. *See* FPA § 316(a) (2005), 16 U.S.C. § 825o(a).

FERC FORM NO. 1/3-Q:
REPORT OF MAJOR ELECTRIC UTILITIES, LICENSEES AND OTHER

IDENTIFICATION

01 Exact Legal Name of Respondent Duke Energy Carolinas, LLC	02 Year/Period of Report End of 2019/Q4
03 Previous Name and Date of Change *(if name changed during year)* / /	
04 Address of Principal Office at End of Period *(Street, City, State, Zip Code)* 550 South Tryon Street, Charlotte, NC 28202	
05 Name of Contact Person Melicia James	06 Title of Contact Person Finance Associate
07 Address of Contact Person *(Street, City, State, Zip Code)* 550 South Tryon Street, Charlotte, NC 28202	

08 Telephone of Contact Person,*Including Area Code* (704) 382-0007	09 This Report Is (1) [X] An Original (2) [ ] A Resubmission	10 Date of Report *(Mo, Da, Yr)* 04/14/2020

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

I have examined this report and to the best of my knowledge, information, and belief all statements of fact contained in this report are correct statements of the business affairs of the respondent and the financial statements, and other financial information contained in this report, conform in all material respects to the Uniform System of Accounts.

01 Name Dwight L. Jacobs	03 Signature	04 Date Signed *(Mo, Da, Yr)*
02 Title SVP, CAO, Tax and Controller	Dwight L. Jacobs	04/14/2020

Title 18, U.S.C. 1001 makes it a crime for any person to knowingly and willingly to make to any Agency or Department of the United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Other Deferred Credits	269	
38	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
39	Accumulated Deferred Income Taxes-Other Property	274-275	
40	Accumulated Deferred Income Taxes-Other	276-277	
41	Other Regulatory Liabilities	278	
42	Electric Operating Revenues	300-301	
43	Regional Transmission Service Revenues (Account 457.1)	302	
44	Sales of Electricity by Rate Schedules	304	
45	Sales for Resale	310-311	
46	Electric Operation and Maintenance Expenses	320-323	
47	Purchased Power	326-327	
48	Transmission of Electricity for Others	328-330	
49	Transmission of Electricity by ISO/RTOs	331	
50	Transmission of Electricity by Others	332	
51	Miscellaneous General Expenses-Electric	335	
52	Depreciation and Amortization of Electric Plant	336-337	
53	Regulatory Commission Expenses	350-351	
54	Research, Development and Demonstration Activities	352-353	
55	Distribution of Salaries and Wages	354-355	
56	Common Utility Plant and Expenses	356	
57	Amounts included in ISO/RTO Settlement Statements	397	
58	Purchase and Sale of Ancillary Services	398	
59	Monthly Transmission System Peak Load	400	
60	Monthly ISO/RTO Transmission System Peak Load	400a	
61	Electric Energy Account	401	
62	Monthly Peaks and Output	401	
63	Steam Electric Generating Plant Statistics	402-403	
64	Hydroelectric Generating Plant Statistics	406-407	
65	Pumped Storage Generating Plant Statistics	408-409	
66	Generating Plant Statistics Pages	410-411	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

Enter in column (c) the terms "none," "not applicable," or "NA," as appropriate, where no information or amounts have been reported for certain pages. Omit pages where the respondents are "none," "not applicable," or "NA".

Stockholders' Reports Check appropriate box:

- [ ] Two copies will be submitted
- [ ] No annual report to stockholders is prepared

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

GENERAL INFORMATION

1. Provide name and title of officer having custody of the general corporate books of account and address of office where the general corporate books are kept, and address of office where any other corporate books of account are kept, if different from that where the general corporate books are kept.

Dwight L. Jacobs
Senior Vice President, Chief Accounting Officer and Controller
550 South Tryon Street
Charlotte, NC 28202

2. Provide the name of the State under the laws of which respondent is incorporated, and date of incorporation. If incorporated under a special law, give reference to such law. If not incorporated, state that fact and give the type of organization and the date organized.

On April 3, 2006 the respondent converted its form of organization from a North Carolina Corporation to a North Carolina limited liability company. The respondent was originally incorporated as a North Carolina corporation on November 27, 1963.

3. If at any time during the year the property of respondent was held by a receiver or trustee, give (a) name of receiver or trustee, (b) date such receiver or trustee took possession, (c) the authority by which the receivership or trusteeship was created, and (d) date when possession by receiver or trustee ceased.

Not applicable

4. State the classes or utility and other services furnished by respondent during the year in each State in which the respondent operated.

Per the 2019 10-K:

Duke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas service area covers approximately 24,000 square miles and supplies electric service to 2.6 million residential, commercial and industrial customers. For information about Duke Energy Carolinas' generating facilities, see Item 2, "Properties." Duke Energy Carolinas is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Substantially all of Duke Energy Carolinas' operations are regulated and qualify for regulatory accounting. Duke Energy Carolinas operates one reportable business segment, Electric Utilities and Infrastructure. For additional information regarding this business segment, including financial information, see Note 3 to the Consolidated Financial Statements, "Business Segments"

5. Have you engaged as the principal accountant to audit your financial statements an accountant who is not the principal accountant for your previous year's certified financial statements?

(1) [ ] Yes...Enter the date when such independent accountant was initially engaged:
(2) [X] No

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CONTROL OVER RESPONDENT

1. If any corporation, business trust, or similar organization or a combination of such organizations jointly held control over the repondent at the end of the year, state name of controlling corporation or organization, manner in which control was held, and extent of control. If control was in a holding company organization, show the chain of ownership or control to the main parent company or organization. If control was held by a trustee(s), state name of trustee(s), name of beneficiary or beneficiearies for whom trust was maintained, and purpose of the trust.

Name of Controlling Organization: Duke Energy Corporation

Manner/Extent of Control: Membership interest in respondent, Duke Energy Carolinas, LLC, is 100% owned by Duke Energy Corporation.

Chain of Ownership/Control to Main Parent company: 100% of the membership interest in respondent, Duke Energy Carolinas, LLC, is owned and controlled by Duke Energy Corporation, which is the publicly held parent company.

See also 2019 Duke Energy Corporation Form 10-K filed with the SEC in February, 2020.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CORPORATIONS CONTROLLED BY RESPONDENT

1. Report below the names of all corporations, business trusts, and similar organizations, controlled directly or indirectly by respondent at any time during the year. If control ceased prior to end of year, give particulars (details) in a footnote.
2. If control was by other means than a direct holding of voting rights, state in a footnote the manner in which control was held, naming any intermediaries involved.
3. If control was held jointly with one or more other interests, state the fact in a footnote and name the other interests.

Definitions
1. See the Uniform System of Accounts for a definition of control.
2. Direct control is that which is exercised without interposition of an intermediary.
3. Indirect control is that which is exercised by the interposition of an intermediary which exercises direct control.
4. Joint control is that in which neither interest can effectively control or direct action without the consent of the other, as where the voting control is equally divided between two holders, or each party holds a veto power over the other. Joint control may exist by mutual agreement or understanding between two or more parties who together have control within the meaning of the definition of control in the Uniform System of Accounts, regardless of the relative voting rights of each party.

Line No.	Name of Company Controlled (a)	Kind of Business (b)	Percent Voting Stock Owned (c)	Footnote Ref. (d)
1	Advance SC LLC	Non-profit	100%	
2	Caldwell Power Company	Refer to column (d)	100%	A
3	Catawba Manufacturing and Electric Power Co.	Refer to column (d)	100%	A
4	Claiborne Energy Services, Inc.	Uranium Enrichment	100%	
5	Duke Energy Receivables Finance Co., LLC	Receivables Finance	100%	
6	Eastover Land Company	Real Estate	100%	
7	Eastover Mining Company	Mining Company	100%	
8	Greenville Gas and Electric Light & Power Co.	Refer to column (d)	100%	A
9	MCP, LLC	Holding Company	100%	
10	Sandy River Timber, LLC	Real Estate	100%	
11	Southern Power Company	Refer to column (d)	100%	A
12	TBP Properties, LLC	Real Estate	100%	
13	TRES Timber, LLC	Real Estate	100%	
14	Wateree Power Company	Refer to column (d)	100%	A
15	Western Carolina Power Company	Refer to column (d)	100%	A
16				
17				
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26				
27				

FOOTNOTE DATA

Schedule Page: 103 Line No.: 2 Column: d

(A): The purpose of this entity is to generate, transmit, and distribute electric power and preserve property rights.

Schedule Page: 103 Line No.: 3 Column: d

Refer to Footnote A on Schedule Page: 103; Line No.: 2; Column: d

Schedule Page: 103 Line No.: 8 Column: d

Refer to Footnote A on Schedule Page: 103; Line No.: 2; Column: d

Schedule Page: 103 Line No.: 11 Column: d

Refer to Footnote A on Schedule Page: 103; Line No.: 2; Column: d

Schedule Page: 103 Line No.: 14 Column: d

Refer to Footnote A on Schedule Page: 103; Line No.: 2; Column: d

Schedule Page: 103 Line No.: 15 Column: d

Refer to Footnote A on Schedule Page: 103; Line No.: 2; Column: d

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OFFICERS

1. Report below the name, title and salary for each executive officer whose salary is $50,000 or more. An "executive officer" of a respondent includes its president, secretary, treasurer, and vice president in charge of a principal business unit, division or function (such as sales, administration or finance), and any other person who performs similar policy making functions.
2. If a change was made during the year in the incumbent of any position, show name and total remuneration of the previous incumbent, and the date the change in incumbency was made.

Line No.	Title (a)	Name of Officer (b)	Salary for Year (c)
1	Chief Executive Officer	Lynn Good	1,390,500
2			
3	Executuve Vice President and Chief Financial Officer	Steven K. Young	738,738
4			
5	Executive Vice President and Chief Operating Officer	Dhiaa Jamil	839,476
6			
7	Executive Vice President and Chief Human Resources	Melissa Anderson	538,274
8	Officer		
9			
10	Executive Vice President, Energy Solutions and	Douglas Esamann	675,000
11	President, Midwest/Florida Regions and Natural Gas		
12	Business (10/01/2019-12/31/2019)		
13			
14	Executive Vice President, External Affairs and	Julia Janson	715,000
15	President, Carolinas Region (10/01/2019-12/31/2019)		
16			
17	State President, NC	Stephen De May	418,937
18			
19	State President, SC	Michael Callahan	281,589
20			
21	Senior Vice President, Corporate Development and	Karl Newlin	484,100
22	Treasurer		
23			
24	Senior Vice President, Chief Accounting Officer, Tax and	Dwight L. Jacobs	311,881
25	Controller		
26			
27	Senior Vice President, Customer Experience and Services	Harry Sideris	453,500
28			
29	Senior Vice President, Chief Transformation and	Brian Savoy	455,559
30	Administrative Officer		
31			
32	Senior Vice President, Legal, Chief Ethics and Comp	David Fountain	418,842
33	Officer and Corp Secretary		
34			
35	Executive Vice President and Chief Legal Officer	Kodwo Ghartey-Tagoe	500,000
36			
37	Executive Vice President, Customer and Delivery and	Lloyd Yates	725,039
38	President, Carolinas Region (01/01/2019-09/30/2019)		
39			
40	Executive Vice President and President, Natural Gas	Franklin Yoho	529,935
41	Business (01/01/2019-10/03/2019)		
42			
43			
44			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DIRECTORS

1. Report below the information called for concerning each director of the respondent who held office at any time during the year. Include in column (a), abbreviated titles of the directors who are officers of the respondent.
2. Designate members of the Executive Committee by a triple asterisk and the Chairman of the Executive Committee by a double asterisk.

Line No.	Name (and Title) of Director (a)	Principal Business Address (b)
1	Lynn J. Good	550 South Tryon Street, Charlotte, NC 28202
2	Chief Executive Officer	
3		
4	Dhiaa Jamil	550 South Tryon Street, Charlotte, NC 28202
5	Executive Vice President & Chief Operating Officer	
6		
7	Julia Janson	550 South Tryon Street, Charlotte, NC 28202
8	Executive Vice President, External Affaairs and President	
9	Carolinas Region (10/01/2019-12/31/2019)	
10		
11	Lloyd Yates	550 South Tryon Street, Charlotte, NC 28202
12	Executive Vice President, Customer & Delivery Operations	
13	and President, Carolinas Region (01/01/2019-09/30/2019)	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent have formula rates? [X] Yes [ ] No

1. Please list the Commission accepted formula rates including FERC Rate Schedule or Tariff Number and FERC proceeding (i.e. Docket No) accepting the rate(s) or changes in the accepted rate.

Line No.	FERC Rate Schedule or Tariff Number	FERC Proceeding
1	273	ER17-2436
2	315	ER19-1789
3	316	ER19-1789
4	317	ER19-1789
5	326	ER19-718
6	327	ER19-1526
7	328	ER19-718
8	329	ER19-1722
9	330	ER19-718
10	331	ER19-1526
11	332	ER19-718
12	333	ER20-212
13	334	ER19-1526
14	335	ER19-1789
15	336	ER20-213
16	337	ER19-718
17	338	ER19-718
18	340	ER19-2634
19	Tariff Volume No. 4, Open Access Transmission	ER19-1576
20	Tariff, 9.0.0	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
FERC Rate Schedule/Tariff Number FERC Proceeding

Does the respondent file with the Commission annual (or more frequent) filings containing the inputs to the formula rate(s)? [X] Yes [ ] No

2. If yes, provide a listing of such filings as contained on the Commission's eLibrary website

Line No.	Accession No.	Document Date \ Filed Date	Docket No.	Description	Formula Rate FERC Rate Schedule Number or Tariff Number
1	20190515-5248	05/15/2019	ER11-3585	Informational Filing 2019	Tariff Volume No. 4, Open
2				Annual Update for the	Access Transmission
3				OATT Formula Transmission	Tariff, 9.0.0
4				Rate of Duke Energy	
5				Carolinas, LLC under	
6				ER11-3585	
7					
8					
9	20190530-5189	05/30/2019	ER11-3585	Revision to May 15, 2019	Tariff Volume No. 4, Open
10				Informational Filing	Access Transmission
11				2019 Annual Update for the	Tariff, 9.0.0
12				OATT Formula	
13				Transmission Rate of	
14				Duke Energy Carolinas,	
15				LLC	
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

INFORMATION ON FORMULA RATES
Formula Rate Variances

1. If a respondent does not submit such filings then indicate in a footnote to the applicable Form 1 schedule where formula rate inputs differ from amounts reported in the Form 1.
2. The footnote should provide a narrative description explaining how the "rate" (or billing) was derived if different from the reported amount in the Form 1.
3. The footnote should explain amounts excluded from the ratebase or where labor or other allocation factors, operating expenses, or other items impacting formula rate inputs differ from amounts reported in Form 1 schedule amounts.
4. Where the Commission has provided guidance on formula rate inputs, the specific proceeding should be noted in the footnote.

Line No.	Page No(s).	Schedule	Column	Line No
1	114	Statement of Income	g	14
2	205	Electric Plant in Service	g	46
3	207	Electric Plant in Service	g	58
4	207	Electric Plant in Service	g	58,75,99
5	219	Accumulated Provision for Depreciation of Electric	b	25,26,28
6		Utility Plant (Account 108)		
7	219	Accumulated Provision for Depreciation of Electric	c	24,25
8		Utiltiy Plant (Account 108)		
9	227	Materials and Supplies - Transmission	c	5
10	234	Accumulated Deferred Income Taxes-Other Property	c	18
11	263	Taxes Accrued, Prepaid, and Charged during year	i	5,10,17,23,27,30,31,32
12				
13	263	Taxes Accrued, Prepaid, and Charged during year	i	5
14	275	Accumulated Deferred Income Taxes - Other Property	k	9
15	276	Accumulated Deferred Income Taxes - Other Property	k	19
16	311	Sales for Reuse	k	Subtotal Non-RQ
17	320	Electric Operation and Maintenance Expense	b	5,12
18	321	Electric Operation and Maintenance Expense	b	90,91,112
19	321	Electric Operation and Maintenance Expense	b	63,76,80,112
20	323	Electric Operation and Maintenance Expense	b	197,191
21	323	Electric Operation and Maintenance Expense	b	185,197
22	336	Depreciation and Amortization of Electric Plant	f	1,7,10
23	336	Depreciation and Amoritzation of Electric Plant	f	1,2,6,7,10
24	354	Distribution of Salaries and Wages	b	20,24
25	354	Distribution of Salaries and Wages	b	65
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Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR

Give particulars (details) concerning the matters indicated below. Make the statements explicit and precise, and number them in accordance with the inquiries. Each inquiry should be answered. Enter "none," "not applicable," or "NA" where applicable. If information which answers an inquiry is given elsewhere in the report, make a reference to the schedule in which it appears.

1. Changes in and important additions to franchise rights: Describe the actual consideration given therefore and state from whom the franchise rights were acquired. If acquired without the payment of consideration, state that fact.
2. Acquisition of ownership in other companies by reorganization, merger, or consolidation with other companies: Give names of companies involved, particulars concerning the transactions, name of the Commission authorizing the transaction, and reference to Commission authorization.
3. Purchase or sale of an operating unit or system: Give a brief description of the property, and of the transactions relating thereto, and reference to Commission authorization, if any was required. Give date journal entries called for by the Uniform System of Accounts were submitted to the Commission.
4. Important leaseholds (other than leaseholds for natural gas lands) that have been acquired or given, assigned or surrendered: Give effective dates, lengths of terms, names of parties, rents, and other condition. State name of Commission authorizing lease and give reference to such authorization.
5. Important extension or reduction of transmission or distribution system: State territory added or relinquished and date operations began or ceased and give reference to Commission authorization, if any was required. State also the approximate number of customers added or lost and approximate annual revenues of each class of service. Each natural gas company must also state major new continuing sources of gas made available to it from purchases, development, purchase contract or otherwise, giving location and approximate total gas volumes available, period of contracts, and other parties to any such arrangements, etc.
6. Obligations incurred as a result of issuance of securities or assumption of liabilities or guarantees including issuance of short-term debt and commercial paper having a maturity of one year or less. Give reference to FERC or State Commission authorization, as appropriate, and the amount of obligation or guarantee.
7. Changes in articles of incorporation or amendments to charter: Explain the nature and purpose of such changes or amendments.
8. State the estimated annual effect and nature of any important wage scale changes during the year.
9. State briefly the status of any materially important legal proceedings pending at the end of the year, and the results of any such proceedings culminated during the year.
10. Describe briefly any materially important transactions of the respondent not disclosed elsewhere in this report in which an officer, director, security holder reported on Page 104 or 105 of the Annual Report Form No. 1, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

PAGE 108 INTENTIONALLY LEFT BLANK
SEE PAGE 109 FOR REQUIRED INFORMATION.

1. None

2. None

3. On August 9, 2018 Duke Energy Carolinas and Northbrook Carolina Hydro II LLC filed a request to transfer the licenses for five different projects that included Gaston Shoals, Bryson, Franklin, Mission, and Tuxedo to Northbrook. The license transfer acceptance closed on August 16th 2019. The Federal Energy Regulatory Commission authorized under Dockets P-2332-111, P-2601-056, P-2603-049, and P-2619-036. The North Carolina Utilities Commission authorized under Docket NO. E-7,SUB 1181. The Public Service Commission of South Carolina authorized under Docket NO.2018-281-E.

4. Duke Energy Carolinas, LLC and Piedmont Natural Gas Company, Inc. provided natural gas at Belews Creek Generation Facility. The agreement was effective in October 2019 for a period of 20 years. The monthly rent amount was $681.2k for 240 months accumulating to $163.4M in the form of Interest totaling 94.6M and a Principal amount of 68.9M.

5. None

6. See Notes to Financial Statements, Note 5, "Debt and Credit Facilities"

7. None

8. The first quarter compensation cycle had an approximate 3% merit increase and resulted in an annualized impact to the business of $13,455,511 covering 5,547 Duke Energy Carolinas' employees.

   During the second quarter of 2019, Duke energy Carolinas had 301 new hires and saw an increase in wages of of 4,493,859.

9. See Notes to Financial Statements, Note 3, "Regulatory Matters" and Note 4, "Commitments and Contingencies"

10. None

11. (Reserved)

12. None

13. There are no changes to major security holders and voting powers of Duke Energy Carolinas, LLC that have occurred during 2019.

The changes in officer and directors for Duke Energy Carolinas, LLC. that occurred during the fourth Quarter 2019 are as follows:

Resignations Effective 12/31/2019

Rodney E. Gaddy	Senior Vice President, Administrative Services
Tanya M. Hamilton	Site Vice President, Harris
James P. Henning	Senior Vice President, Customer Services
Emily G. Henson	Vice President Operations - Customer Delivery

Rufus Stanley Jackson	Vice President Operations - Customer Delivery
Jackie Joyner	Vice President Operations - Customer Delivery
Kim Maza	Vice President, Nuclear Corporate Operations
Lee T. Mazzocchi	Senior Vice President, Grid Solutions

Appointments Effective 12/31/2019

Tanya M. Hamilton	Senior Vice President, Nuclear Corporate
Kim Maza	Site Vice President, Harris

Resignations Effective 11/30/2019

Scott L. Batson	Regional Senior Vice President, Customer Delivery Carolinas
Donald E. Broadhurst	Vice President Operations - Customer Delivery
Eric S. Grant	Vice President, Fuels and Systems Optimization
Larry E. Hatcher	Senior Vice President, Customer Delivery Governance, Programs and Support
Forest W. Rogers Jr.	Vice President, Transmission Maintenance and Construction
L. Stanford Sherrill, Jr.	Vice President, Strategic HR Business Solutions, Employee and Labor Relations
Thomas Silinski	Vice President, Total Rewards and Human Resource Operations

Appointments Effective 11/30/2019

Scott L. Baston	Senior Vice President and Chief Distribution Officer
Jeffrey W. Bramblett	Vice President, Nuclear Corporate Operations
William H. Fowler Carolinas	Regional Senior Vice President, Customer Delivery -
Eric S. Grant	Senior Vice President, Customer Delivery Governance, Programs & Support
Larry E. Hatcher	Senior Vice President, Customer Services
Forest W. Rogers Jr. Construction	Senior Vice President, Transmission Maintenance and
L. Stanford Sherrill, Jr.	Vice President, Human Resources and Employee & Labor Relations
Thomas Silinski	Vice President, Human Resources, Total Rewards & HR Operations
John A. Verderame	Vice President, Fuels and System Optimization
Bryan P. Walsh	Vice President, Central Services and Organizational Effectiveness

Resignations Effective 10/31/2019

Melissa H. Anderson	Executive Vice President, Administration and Chief Human Resources Officer

Donna T. Council	Vice President, Accounts Payable Stabilization Project
Douglas F. Esamann	Executive Vice President, Energy Solutions and President, Midwest and Florida Regions
Kodwo Ghartey-Tagoe	President, South Carolina
Julia S. Janson	Executive Vice President, External Affairs and Chief Legal Officer
Louis E. Renjel	Senior Vice President, Federal Government Affairs and Strategic Policy
Brian D. Savoy	Senior Vice President, Business Transformation and Technology
Harry K. Sideris	Senior Vice President and Chief Distribution Officer
Peter E. Toomey	Senior Vice President, Enterprise Strategy and Planning

Appointments Effective 10/31/2019

Melissa H. Anderson	Executive Vice President and Chief Human Resources Officer
Cari P. Boyce	Senior Vice President, Enterprise Strategy and Planning
Michael P. Callahan	President, South Carolina
Donna T. Council	Vice President, Administrative Services
Douglas F. Esamann	Executive Vice President, Energy Solutions and President Midwest/Florida Regions and Natural Gas Business
Kowdo Ghartey-Tagoe	Executive Vice President and Chief Legal Officer
Julia S. Janson	Executive Vice President, External Affairs and President, Carolinas Region
Louis E. Renjel	Senior Vice President, Federal Government and Corporate Affairs
Brian D. Savoy	Senior Vice President, Chief Transformation and Administrative Officer
Harry K. Sideris	Senior Vice President, Customer Experience and Services
Peter E. Toomey	Senior Vice President, Strategic Regulatory Initiatives

Resignations Effective 9/30/2019

Gideon, William R.	Site Vice President, Brunswick
Yates, Lloyd M.	Executive Vice President, Customer and Delivery Operations And President, Carolinas Region

Appointments Effective 9/30/2019

Krakuszecki, John A.	Site Vice President, Brunswick

Resignations Effective 7/1/2019

Draovitch, Paul	Senior Vice President, Environmental, Health and Safety
Stone, Jeffrey M.	Vice President, Audit Services and Ethics and Compliance
Wells, James	Vice President, Coal Combustion Products, Environmental, Health & Safety

Appointments Effective 7/1/2019

Draovitch, Paul	Senior Vice President, Environmental, Health and Safety and Operations Support
Hunter, Amelia D.	Vice President, Corporate Audit Services
Wells, James	Vice President, Coal Combustion Products, Environmental, Health and safety

Resignations effective 6/30/19

Richard W. Bagley	Vice President, Transmission Engineering and Asset Management

Appointments effective 6/19/19

Bonnie B. Titone	Vice President and Chief Information Officer

Appointments effective 6/01/19

Ben I. Harrison Jr.	Vice President, Transmission Engineering and Asset Management

Appointments effective 5/01/19

Jon F. Kerin	Vice President Enterprise Operations Business Transformation
Martha S. Purser	Engineer (under First Mortgage Bond Indenture)

Resignations effective 3/01/18

Louis E. Renjel	Vice President, Federal Government Affairs and Strategic Policy

Appointments effective 3/01/18

Louis E. Renjel	Senior Vice President, Federal Government Affairs and Strategic Policy

Resignations effective 2/28/19

Jeffrey M. Stone	Vice President, Corporate Audit Services
Sandra S. Wyckoff	Vice President, Ethics and Compliance

Appointments effective 2/28/19

Jeffrey M. Stone	Vice President, Audit Services and Ethics and Compliance

Resignations effective 2/01/19

Robert F. Caldwell	Senior Vice President and President, Duke Energy Renewables and Distributed Energy
Donna T. Council	Vice President, HR Strategic Business Solutions
Swati V. Daji	Senior Vice President, Customer Solutions
Joni Y. Davis	Vice President, Chief Diversity and Inclusion Officer
Joseph W. Donahue	Vice President, Nuclear Engineering
Clark S. Gillespy	Senior Vice President, Economic Development

Thomas Cooper Monroe, III	Director, State Tax
L. Stanford Sherrill, Jr.	Vice President, Talent Acquisition and Workforce Development

Appointments effective 2/01/19

Robert F. Caldwell	Senior Vice President and President, Duke Energy Renewables and Business Development
Donna T. Council	Vice President, Accounts Payable Stabilization Project
Swati V. Daji	Senior Vice President, Customer Solutions and Strategies
Joni Y. Davis	Vice President, Chief Diversity and Inclusion Officer, Talent Acquisition and Workforce Development
Thomas Cooper Monroe, III	Vice President, Tax
L. Stanford Sherrill, Jr.	Vice President, Strategic HR Business Solutions, Employee and Labor Relations
Steven M. Snider	Vice President, Nuclear Engineering
Peter E. Toomey	Senior Vice President, Enterprise Strategy and Planning

Resignations effective 1/01/19

Dwight L. Jacobs	Senior Vice President, Chief Accounting Officer and Controller

Appointments effective 1/01/19

Dwight L. Jacobs	Senior Vice President, Chief Accounting Officer, Tax and Controller

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	45,648,973,414	41,161,863,023
3	Construction Work in Progress (107)	200-201	1,377,950,765	1,632,658,461
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		47,026,924,179	42,794,521,484
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	16,817,702,401	15,937,831,422
6	Net Utility Plant (Enter Total of line 4 less 5)		30,209,221,778	26,856,690,062
7	Nuclear Fuel in Process of Ref., Conv.,Enrich., and Fab. (120.1)	202-203	353,842,409	276,467,667
8	Nuclear Fuel Materials and Assemblies-Stock Account (120.2)		1	1
9	Nuclear Fuel Assemblies in Reactor (120.3)		1,108,922,936	1,152,233,077
10	Spent Nuclear Fuel (120.4)		434,419,218	475,269,001
11	Nuclear Fuel Under Capital Leases (120.6)		0	0
12	(Less) Accum. Prov. for Amort. of Nucl. Fuel Assemblies (120.5)	202-203	1,085,918,361	1,089,674,019
13	Net Nuclear Fuel (Enter Total of lines 7-11 less 12)		811,266,203	814,295,727
14	Net Utility Plant (Enter Total of lines 6 and 13)		31,020,487,981	27,670,985,789
15	Utility Plant Adjustments (116)		1,012,652	1,012,652
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		131,017,053	119,145,876
19	(Less) Accum. Prov. for Depr. and Amort. (122)		44,059,231	41,247,904
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	13,114,070	13,114,081
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	0
24	Other Investments (124)		94,370	94,370
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		4,698,684,072	3,771,013,238
29	Special Funds (Non Major Only) (129)		0	0
30	Long-Term Portion of Derivative Assets (175)		0	0
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	207,518
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		4,798,850,334	3,862,327,179
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		17,918,730	32,258,744
36	Special Deposits (132-134)		0	0
37	Working Fund (135)		300,000	300,000
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		403,887,593	456,075,858
41	Other Accounts Receivable (143)		251,468,704	166,247,610
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		9,792,587	9,138,649
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		129,185,628	244,703,341
45	Fuel Stock (151)	227	230,172,338	220,760,888
46	Fuel Stock Expenses Undistributed (152)	227	0	0
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	721,659,754	682,226,291
49	Merchandise (155)	227	0	0
50	Other Materials and Supplies (156)	227	-4,049	103,378
51	Nuclear Materials Held for Sale (157)	202-203/227	0	0
52	Allowances (158.1 and 158.2)	228-229	53,693,503	46,163,658

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	0
54	Stores Expense Undistributed (163)	227	44,056,245	45,188,768
55	Gas Stored Underground - Current (164.1)		0	0
56	Liquefied Natural Gas Stored and Held for Processing (164.2-164.3)		0	0
57	Prepayments (165)		28,888,827	23,491,197
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		0	0
60	Rents Receivable (172)		545,731	236,004
61	Accrued Utility Revenues (173)		262,297,149	267,458,428
62	Miscellaneous Current and Accrued Assets (174)		6,242,526	12,410,350
63	Derivative Instrument Assets (175)		0	0
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		0	0
65	Derivative Instrument Assets - Hedges (176)		0	508,451
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	207,518
67	Total Current and Accrued Assets (Lines 34 through 66)		2,140,520,092	2,188,786,799
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		59,000,689	57,472,450
70	Extraordinary Property Losses (182.1)	230a	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230b	366,766,246	0
72	Other Regulatory Assets (182.3)	232	3,720,926,188	3,988,381,653
73	Prelim. Survey and Investigation Charges (Electric) (183)		7,039,298	9,500,938
74	Preliminary Natural Gas Survey and Investigation Charges 183.1)		0	0
75	Other Preliminary Survey and Investigation Charges (183.2)		0	0
76	Clearing Accounts (184)		833,581	910,613
77	Temporary Facilities (185)		0	0
78	Miscellaneous Deferred Debits (186)	233	987,491,346	1,091,462,938
79	Def. Losses from Disposition of Utility Plt. (187)		0	0
80	Research, Devel. and Demonstration Expend. (188)	352-353	0	0
81	Unamortized Loss on Reaquired Debt (189)		50,997,878	57,438,955
82	Accumulated Deferred Income Taxes (190)	234	3,270,273,770	2,697,261,240
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		8,463,328,996	7,902,428,787
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		46,424,200,055	41,625,541,206

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [x] An Original (2) [ ] A Resubmission	04/14/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	PROPRIETARY CAPITAL			
2	Common Stock Issued (201)	250-251	0	0
3	Preferred Stock Issued (204)	250-251	0	0
4	Capital Stock Subscribed (202, 205)		0	0
5	Stock Liability for Conversion (203, 206)		0	0
6	Premium on Capital Stock (207)		0	0
7	Other Paid-In Capital (208-211)	253	3,725,067,453	3,725,067,453
8	Installments Received on Capital Stock (212)	252	0	0
9	(Less) Discount on Capital Stock (213)	254	0	0
10	(Less) Capital Stock Expense (214)	254b	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	9,090,656,063	7,963,467,563
12	Unappropriated Undistributed Subsidiary Earnings (216.1)	118-119	4,810,163	4,810,163
13	(Less) Reaquired Capital Stock (217)	250-251	0	0
14	Noncorporate Proprietorship (Non-major only) (218)		0	0
15	Accumulated Other Comprehensive Income (219)	122(a)(b)	-7,286,843	-6,167,891
16	Total Proprietary Capital (lines 2 through 15)		12,813,246,836	11,687,177,288
17	LONG-TERM DEBT			
18	Bonds (221)	256-257	10,708,317,678	9,909,011,177
19	(Less) Reaquired Bonds (222)	256-257	0	0
20	Advances from Associated Companies (223)	256-257	300,000,000	300,000,000
21	Other Long-Term Debt (224)	256-257	791,498,466	698,261,570
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		23,340,288	23,479,383
24	Total Long-Term Debt (lines 18 through 23)		11,776,475,856	10,883,793,364
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		274,737,695	103,966,297
27	Accumulated Provision for Property Insurance (228.1)		121,296,064	108,413,219
28	Accumulated Provision for Injuries and Damages (228.2)		606,243,808	633,919,490
29	Accumulated Provision for Pensions and Benefits (228.3)		79,508,958	94,896,447
30	Accumulated Miscellaneous Operating Provisions (228.4)		4,447,954	4,538,620
31	Accumulated Provision for Rate Refunds (229)		148,821,012	182,332,111
32	Long-Term Portion of Derivative Instrument Liabilities		0	0
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		9,838,275	9,127,400
34	Asset Retirement Obligations (230)		5,734,233,569	3,948,779,041
35	Total Other Noncurrent Liabilities (lines 26 through 34)		6,979,127,335	5,085,972,625
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		934,047,131	973,427,628
39	Notes Payable to Associated Companies (233)		28,975,000	438,690,000
40	Accounts Payable to Associated Companies (234)		233,331,103	252,784,648
41	Customer Deposits (235)		129,105,560	126,584,652
42	Taxes Accrued (236)	262-263	42,439,403	170,427,273
43	Interest Accrued (237)		115,047,741	102,018,472
44	Dividends Declared (238)		0	0
45	Matured Long-Term Debt (239)		0	0

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [x] An Original (2) [ ] A Resubmission	04/14/2020	end of 2019/Q4

COMPARATIVE BALANCE SHEET (LIABILITIES AND OTHER CREDITS) (Continued)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		9,712,518	12,372,163
48	Miscellaneous Current and Accrued Liabilities (242)		393,739,710	372,526,662
49	Obligations Under Capital Leases-Current (243)		34,567,442	5,304,078
50	Derivative Instrument Liabilities (244)		6,242,526	9,410,350
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		0	0
52	Derivative Instrument Liabilities - Hedges (245)		42,805,336	21,253,078
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		9,838,275	9,127,400
54	Total Current and Accrued Liabilities (lines 37 through 53)		1,960,175,195	2,475,671,604
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		0	0
57	Accumulated Deferred Investment Tax Credits (255)	266-267	231,070,485	231,369,819
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	573,365,513	573,392,182
60	Other Regulatory Liabilities (254)	278	4,899,651,112	4,301,714,243
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	0	0
63	Accum. Deferred Income Taxes-Other Property (282)		4,950,406,777	4,343,192,939
64	Accum. Deferred Income Taxes-Other (283)		2,240,680,946	2,043,257,142
65	Total Deferred Credits (lines 56 through 64)		12,895,174,833	11,492,926,325
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		46,424,200,055	41,625,541,206

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF INCOME

Quarterly
1. Report in column (c) the current year to date balance. Column (c) equals the total of adding the data in column (g) plus the data in column (i) plus the data in column (k). Report in column (d) similar data for the previous year. This information is reported in the annual filing only.
2. Enter in column (e) the balance for the reporting quarter and in column (f) the balance for the same three month period for the prior year.
3. Report in column (g) the quarter to date amounts for electric utility function; in column (i) the quarter to date amounts for gas utility, and in column (k) the quarter to date amounts for other utility function for the current year quarter.
4. Report in column (h) the quarter to date amounts for electric utility function; in column (j) the quarter to date amounts for gas utility, and in column (l) the quarter to date amounts for other utility function for the prior year quarter.
5. If additional columns are needed, place them in a footnote.

Annual or Quarterly if applicable
5. Do not report fourth quarter data in columns (e) and (f)
6. Report amounts for accounts 412 and 413, Revenues and Expenses from Utility Plant Leased to Others, in another utility columnin a similar manner to a utility department. Spread the amount(s) over lines 2 thru 26 as appropriate. Include these amounts in columns (c) and (d) totals.
7. Report amounts in account 414, Other Utility Operating Income, in the same manner as accounts 412 and 413 above.

Line No.	Title of Account (a)	(Ref.) Page No. (b)	Total Current Year to Date Balance for Quarter/Year (c)	Total Prior Year to Date Balance for Quarter/Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
1	UTILITY OPERATING INCOME					
2	Operating Revenues (400)	300-301	7,393,535,847	7,273,364,536		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	3,004,743,504	3,158,322,869		
5	Maintenance Expenses (402)	320-323	572,097,385	693,767,447		
6	Depreciation Expense (403)	336-337	1,100,429,701	1,029,546,198		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337	51,093			
8	Amort. & Depl. of Utility Plant (404-405)	336-337	68,414,112	65,860,546		
9	Amort. of Utility Plant Acq. Adj. (406)	336-337				
10	Amort. Property Losses, Unrecov Plant and Regulatory Study Costs (407)		54,548,296			
11	Amort. of Conversion Expenses (407)					
12	Regulatory Debits (407.3)		210,782,686	149,999,980		
13	(Less) Regulatory Credits (407.4)		23,180,730	51,895,694		
14	Taxes Other Than Income Taxes (408.1)	262-263	288,014,156	291,829,421		
15	Income Taxes - Federal (409.1)	262-263	170,708,943	-3,506,659		
16	- Other (409.1)	262-263	13,063,526	7,058,710		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	1,585,402,690	1,425,900,089		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	1,469,384,000	1,088,738,036		
19	Investment Tax Credit Adj. - Net (411.4)	266	-4,229,733	-5,258,630		
20	(Less) Gains from Disp. of Utility Plant (411.6)					
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		158	-250,563		
23	Losses from Disposition of Allowances (411.9)					
24	Accretion Expense (411.10)					
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		5,571,461,471	5,673,136,804		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		1,822,074,376	1,600,227,732		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

9. Use page 122 for important notes regarding the statement of income for any account thereof.
10. Give concise explanations concerning unsettled rate proceedings where a contingency exists such that refunds of a material amount may need to be made to the utility's customers or which may result in material refund to the utility with respect to power or gas purchases. State for each year effected the gross revenues or costs to which the contingency relates and the tax effects together with an explanation of the major factors which affect the rights of the utility to retain such revenues or recover amounts paid with respect to power or gas purchases.
11 Give concise explanations concerning significant amounts of any refunds made or received during the year resulting from settlement of any rate proceeding affecting revenues received or costs incurred for power or gas purches, and a summary of the adjustments made to balance sheet, income, and expense accounts.
12. If any notes appearing in the report to stokholders are applicable to the Statement of Income, such notes may be included at page 122.
13. Enter on page 122 a concise explanation of only those changes in accounting methods made during the year which had an effect on net income, including the basis of allocations and apportionments from those used in the preceding year. Also, give the appropriate dollar effect of such changes.
14. Explain in a footnote if the previous year's/quarter's figures are different from that reported in prior reports.
15. If the columns are insufficient for reporting additional utility departments, supply the appropriate account titles report the information in a footnote to this schedule.

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
Current Year to Date (in dollars) (g)	Previous Year to Date (in dollars) (h)	Current Year to Date (in dollars) (i)	Previous Year to Date (in dollars) (j)	Current Year to Date (in dollars) (k)	Previous Year to Date (in dollars) (l)	
						1
7,393,535,847	7,273,364,536					2
						3
3,004,743,504	3,158,322,869					4
572,097,385	693,767,447					5
1,100,429,701	1,029,546,198					6
51,093	65,860,546					7
68,414,112						8
						9
54,548,296						10
						11
210,782,686	149,999,980					12
23,180,730	51,895,694					13
288,014,156	291,829,421					14
170,708,943	-3,506,659					15
13,063,526	7,058,710					16
1,585,402,690	1,425,900,089					17
1,469,384,000	1,088,738,036					18
-4,229,733	-5,258,630					19
						20
						21
158	-250,563					22
						23
						24
5,571,461,471	5,673,136,804					25
1,822,074,376	1,600,227,732					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF INCOME FOR THE YEAR (continued)

Line No.	Title of Account (a)	(Ref.) Page No. (b)	TOTAL Current Year (c)	TOTAL Previous Year (d)	Current 3 Months Ended Quarterly Only No 4th Quarter (e)	Prior 3 Months Ended Quarterly Only No 4th Quarter (f)
27	Net Utility Operating Income (Carried forward from page 114)		1,822,074,376	1,600,227,732		
28	Other Income and Deductions					
29	Other Income					
30	Nonutilty Operating Income					
31	Revenues From Merchandising, Jobbing and Contract Work (415)					
32	(Less) Costs and Exp. of Merchandising, Job. & Contract Work (416)		14,336	110,300		
33	Revenues From Nonutility Operations (417)		26,534,625	21,115,902		
34	(Less) Expenses of Nonutility Operations (417.1)		16,928,830	19,614,542		
35	Nonoperating Rental Income (418)		-3,033,908	-2,946,961		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,421,319	927,820		
38	Allowance for Other Funds Used During Construction (419.1)		41,617,164	73,017,944		
39	Miscellaneous Nonoperating Income (421)		43,164,552	19,209,311		
40	Gain on Disposition of Property (421.1)		64,035			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		92,824,621	91,599,174		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		386,515	392,522		
44	Miscellaneous Amortization (425)		9,979	9,979		
45	Donations (426.1)		6,027,482	9,525,160		
46	Life Insurance (426.2)		-56,600	-60,141		
47	Penalties (426.3)		134,649	1,830,590		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		5,532,838	4,083,343		
49	Other Deductions (426.5)		20,672,360	197,967,254		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		32,707,223	213,748,707		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	2,906,647	3,463,726		
53	Income Taxes-Federal (409.2)	262-263	-5,427,806	-4,970,131		
54	Income Taxes-Other (409.2)	262-263	-489,103	-463,781		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	38,422,606	19,094,320		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	17,354,023	47,570,994		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		18,058,321	-30,446,860		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		42,059,077	-91,702,673		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		468,477,437	457,531,046		
63	Amort. of Debt Disc. and Expense (428)		7,219,499	6,364,114		
64	Amortization of Loss on Reaquired Debt (428.1)		6,441,077	6,441,077		
65	(Less) Amort. of Premium on Debt-Credit (429)					
66	(Less) Amortization of Gain on Reaquired Debt-Credit (429.1)					
67	Interest on Debt to Assoc. Companies (430)		18,214,465	16,249,127		
68	Other Interest Expense (431)		-7,991,920	-13,246,775		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		30,415,605	35,192,184		
70	Net Interest Charges (Total of lines 62 thru 69)		461,944,953	438,146,405		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		1,402,188,500	1,070,378,654		
72	Extraordinary Items					
73	Extraordinary Income (434)					
74	(Less) Extraordinary Deductions (435)					
75	Net Extraordinary Items (Total of line 73 less line 74)					
76	Income Taxes-Federal and Other (409.3)	262-263				
77	Extraordinary Items After Taxes (line 75 less line 76)					
78	Net Income (Total of line 71 and 77)		1,402,188,500	1,070,378,654		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		7,835,985,662	7,527,852,813
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10				
11				
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)			
16	Balance Transferred from Income (Account 433 less Account 418.1)		1,402,188,500	1,070,378,654
17	Appropriations of Retained Earnings (Acct. 436)			
18			-8,369,245	(12,245,805)
19				
20				
21				
22	TOTAL Appropriations of Retained Earnings (Acct. 436)		-8,369,245	(12,245,805)
23	Dividends Declared-Preferred Stock (Account 437)			
24				
25				
26				
27				
28				
29	TOTAL Dividends Declared-Preferred Stock (Acct. 437)			
30	Dividends Declared-Common Stock (Account 438)			
31	Cash Dividend to Parent		-275,000,000	(750,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-275,000,000	(750,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		8,954,804,917	7,835,985,662
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF RETAINED EARNINGS

1. Do not report Lines 49-53 on the quarterly version.
2. Report all changes in appropriated retained earnings, unappropriated retained earnings, year to date, and unappropriated undistributed subsidiary earnings for the year.
3. Each credit and debit during the year should be identified as to the retained earnings account in which recorded (Accounts 433, 436 - 439 inclusive). Show the contra primary account affected in column (b)
4. State the purpose and amount of each reservation or appropriation of retained earnings.
5. List first account 439, Adjustments to Retained Earnings, reflecting adjustments to the opening balance of retained earnings. Follow by credit, then debit items in that order.
6. Show dividends for each class and series of capital stock.
7. Show separately the State and Federal income tax effect of items shown in account 439, Adjustments to Retained Earnings.
8. Explain in a footnote the basis for determining the amount reserved or appropriated. If such reservation or appropriation is to be recurrent, state the number and annual amounts to be reserved or appropriated as well as the totals eventually to be accumulated.
9. If any notes appearing in the report to stockholders are applicable to this statement, include them on pages 122-123.

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
41				
42				
43				
44				
45	TOTAL Appropriated Retained Earnings (Account 215)			
	APPROP. RETAINED EARNINGS - AMORT. Reserve, Federal (Account 215.1)			
46	TOTAL Approp. Retained Earnings-Amort. Reserve, Federal (Acct. 215.1)		135,851,146	127,481,901
47	TOTAL Approp. Retained Earnings (Acct. 215, 215.1) (Total 45,46)		135,851,146	127,481,901
48	TOTAL Retained Earnings (Acct. 215, 215.1, 216) (Total 38, 47) (216.1)		9,090,656,063	7,963,467,563
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)		4,810,163	4,810,163
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)		4,810,163	4,810,163

FOOTNOTE DATA

Schedule Page: 118 Line No.: 46 Column: c

A specified reasonable rate of return upon the net investment in the hydro project(s) shall be used for determining surplus earnings of the project for the establishment and maintenance of amortization reserves. The Licensee shall set aside in a project amortization reserve account at the end of each fiscal year one half of the project surplus earnings, if any, in excess of the specified rate of return per annum on the net investment. To the extent that there is a deficiency of project earnings below the specified rate of return per annum for any fiscal year, the Licensee shall deduct the amount of that deficiency from the amount of any surplus earnings subsequently accumulated, until absorbed.

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
1	Net Cash Flow from Operating Activities:		
2	Net Income (Line 78(c) on page 117)	1,402,188,500	1,070,378,654
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	1,100,480,794	1,029,546,198
5	Amortization of Primary Nuclear Fuel	594,709,269	452,081,848
6	Provision for Rate Refunds	36,159,882	182,332,111
7	Contributions to Qualified Pensions	-6,658,183	-45,625,440
8	Deferred Income Taxes (Net)	137,087,273	308,685,379
9	Investment Tax Credit Adjustment (Net)	-4,229,734	-5,258,630
10	Net (Increase) Decrease in Receivables	102,113,640	-215,223,976
11	Net (Increase) Decrease in Inventory	-32,779,829	24,589,340
12	Net (Increase) Decrease in Allowances Inventory	-7,529,845	-7,468,735
13	Net Increase (Decrease) in Payables and Accrued Expenses	-283,782,249	206,969,649
14	Net (Increase) Decrease in Other Regulatory Assets	-203,080,079	-158,580,215
15	Net Increase (Decrease) in Other Regulatory Liabilities	181,074,051	-2,815,746
16	(Less) Allowance for Other Funds Used During Construction	41,617,164	73,017,943
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Impairment Charges	16,937,425	191,963,296
19	Payments for asset reitirement obligations	-278,116,622	-230,453,262
20	Accrued Pension and other post-retirement benefit costs	-4,760,441	3,688,980
21	Other	-24,186,164	-231,410,211
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	2,684,010,524	2,500,381,297
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-2,444,194,443	-2,506,218,919
27	Gross Additions to Nuclear Fuel	-311,913,894	-266,581,709
28	Gross Additions to Common Utility Plant		
29	Gross Additions to Nonutility Plant		
30	(Less) Allowance for Other Funds Used During Construction	-41,617,164	-73,017,943
31	Other (provide details in footnote):		
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-2,714,491,173	-2,699,782,685
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)		
38			
39	Investments in and Advances to Assoc. and Subsidiary Companies		
40	Contributions and Advances from Assoc. and Subsidiary Companies		
41	Disposition of Investments in (and Advances to)		
42	Associated and Subsidiary Companies		
43			
44	Purchase of Investment Securities (a)	-1,657,814,375	-1,810,081,968
45	Proceeds from Sales of Investment Securities (a)	1,657,814,375	1,810,081,968

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENT OF CASH FLOWS

(1) Codes to be used:(a) Net Proceeds or Payments;(b)Bonds, debentures and other long-term debt; (c) Include commercial paper; and (d) Identify separately such items as investments, fixed assets, intangibles, etc.
(2) Information about noncash investing and financing activities must be provided in the Notes to the Financial statements. Also provide a reconciliation between "Cash and Cash Equivalents at End of Period" with related amounts on the Balance Sheet.
(3) Operating Activities - Other: Include gains and losses pertaining to operating activities only. Gains and losses pertaining to investing and financing activities should be reported in those activities. Show in the Notes to the Financials the amounts of interest paid (net of amount capitalized) and income taxes paid.
(4) Investing Activities: Include at Other (line 31) net cash outflow to acquire other companies. Provide a reconciliation of assets acquired with liabilities assumed in the Notes to the Financial Statements. Do not include on this statement the dollar amount of leases capitalized per the USofA General Instruction 20; instead provide a reconciliation of the dollar amount of leases capitalized with the plant cost.

Line No.	Description (See Instruction No. 1 for Explanation of Codes) (a)	Current Year to Date Quarter/Year (b)	Previous Year to Date Quarter/Year (c)
46	Loans Made or Purchased		
47	Collections on Loans		
48	Cost of Removal net of salvage	-178,115,877	-125,186,605
49	Net (Increase) Decrease in Receivables		
50	Net (Increase) Decrease in Inventory		
51	Net (Increase) Decrease in Allowances Held for Speculation		
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-2,892,607,050	-2,824,969,290
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)	892,204,487	1,994,522,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65			
66	Net Increase in Short-Term Debt (c)		
67	Other (provide details in footnote):	-7,117,144	-33,814,359
68			
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	885,087,343	1,960,707,641
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-6,115,831	-1,204,801,930
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Net Increase (Decrease) in Intercompany Notes	-409,715,000	335,059,000
78	Net Decrease in Short-Term Debt (c)		
79	Cash Dividend to Parent	-275,000,000	-750,000,000
80	Dividends on Preferred Stock		
81	Dividends on Common Stock		
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	194,256,512	340,964,711
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-14,340,014	16,376,718
87			
88	Cash and Cash Equivalents at Beginning of Period	32,558,744	16,182,026
89			
90	Cash and Cash Equivalents at End of period	18,218,730	32,558,744

Schedule Page: 120 Line No.: 21 Column: b

Claims and expenses related to injuries and damages	(49,816,134)
Deferral of Storm Costs	(21,718,319)
Charitable contributions related to Piedmont merger commitments	(11,900,000)
Net Retiree Medical Reimbursements	(9,955,942)
Other	(1,912,499)
Nuclear Insurance Property Reserve	12,882,884
Insurance proceeds for asbestosis claims	17,251,637
Cost of removal on final retired plants	40,982,209
Total	(24,186,164)

Schedule Page: 120 Line No.: 21 Column: c

Deferral of Storm Costs	(147,910,351)
Claims and expenses related to injuries and damages	(42,822,757)
Debt return on Coal Ash Compliance Costs	(27,722,865)
Charitable contributions related to Piedmont merger commitments	(11,900,000)
Rate Case Support expenses	(11,507,219)
Miscellaneous prepaid expenses	(8,192,733)
Cost of removal on final retired plants	(7,171,053)
Preliminary surveys and investigation	(5,932,427)
Other	(999,169)
Insurance proceeds for asbestosis claims	32,748,363
Total	(231,410,211)

Schedule Page: 120 Line No.: 48 Column: b

Cost of removal of utility plant, net of salvage value	(182,934,348)
Proceeds from Sales of Hydro Plants	4,818,471
Total	(178,115,877)

Schedule Page: 120 Line No.: 48 Column: c

Cost of removal of utility plant, net of salvage value	(125,186,605)

Schedule Page: 120 Line No.: 67 Column: b

Issuance Costs	(5,999,223)
Unamortized Debt Expenses associated with Master Credit Facilities	(1,089,375)
Other	(28,546)
Total	(7,117,144)

Schedule Page: 120 Line No.: 67 Column: c

Interconnection Agreement with NTE Energy	(21,611,598)
Issuance Costs	(11,279,445)
Unamortized Debt Expenses associated with Master Credit Facilities	(923,316)
Total	(33,814,359)

Schedule Page: 120 Line No.: 86 Column: b

Accrued capital expenditures	346,628,359
Supplemental disclosures:	
Cash paid for interest, net of amount capitalized	432,925,674
Cash paid for income taxes, net	121,654,681

Schedule Page: 120 Line No.: 86 Column: c

Accrued capital expenditures	301,737,150
Supplemental disclosures:	
Cash paid for interest, net of amount capitalized	452,336,331

FOOTNOTE DATA

Cash paid for income taxes, net	88,589,194

Schedule Page: 120 Line No.: 88 Column: b

Cash and working funds (131 & 135)	32,558,744
Special deposits (132 - 134)	0
Temporary cash investments	0
Total	32,558,744

Schedule Page: 120 Line No.: 88 Column: c

Cash and working funds (131 & 135)	16,182,026
Special deposits (132 & 134)	0
Temporary cash investments	0
Total	16,182,026

Schedule Page: 120 Line No.: 90 Column: b

Cash and working funds (131 & 135)	18,218,730
Special deposits (132 - 134)	0
Temporary cash investments	0
Total	18,218,730

Schedule Page: 120 Line No.: 90 Column: c

Cash and working funds (131 & 135)	32,558,744
Special deposits (132 - 134)	0
Temporary cash investments	0
Total	32,558,744

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

NOTES TO FINANCIAL STATEMENTS

1. Use the space below for important notes regarding the Balance Sheet, Statement of Income for the year, Statement of Retained Earnings for the year, and Statement of Cash Flows, or any account thereof. Classify the notes according to each basic statement, providing a subheading for each statement except where a note is applicable to more than one statement.
2. Furnish particulars (details) as to any significant contingent assets or liabilities existing at end of year, including a brief explanation of any action initiated by the Internal Revenue Service involving possible assessment of additional income taxes of material amount, or of a claim for refund of income taxes of a material amount initiated by the utility. Give also a brief explanation of any dividends in arrears on cumulative preferred stock.
3. For Account 116, Utility Plant Adjustments, explain the origin of such amount, debits and credits during the year, and plan of disposition contemplated, giving references to Cormmission orders or other authorizations respecting classification of amounts as plant adjustments and requirements as to disposition thereof.
4. Where Accounts 189, Unamortized Loss on Reacquired Debt, and 257, Unamortized Gain on Reacquired Debt, are not used, give an explanation, providing the rate treatment given these items. See General Instruction 17 of the Uniform System of Accounts.
5. Give a concise explanation of any retained earnings restrictions and state the amount of retained earnings affected by such restrictions.
6. If the notes to financial statements relating to the respondent company appearing in the annual report to the stockholders are applicable and furnish the data required by instructions above and on pages 114-121, such notes may be included herein.
7. For the 3Q disclosures, respondent must provide in the notes sufficient disclosures so as to make the interim information not misleading. Disclosures which would substantially duplicate the disclosures contained in the most recent FERC Annual Report may be omitted.
8. For the 3Q disclosures, the disclosures shall be provided where events subsequent to the end of the most recent year have occurred which have a material effect on the respondent. Respondent must include in the notes significant changes since the most recently completed year in such items as: accounting principles and practices; estimates inherent in the preparation of the financial statements; status of long-term contracts; capitalization including significant new borrowings or modifications of existing financing agreements; and changes resulting from business combinations or dispositions. However were material contingencies exist, the disclosure of such matters shall be provided even though a significant change since year end may not have occurred.
9. Finally, if the notes to the financial statements relating to the respondent appearing in the annual report to the stockholders are applicable and furnish the data required by the above instructions, such notes may be included herein.

PAGE 122 INTENTIONALLY LEFT BLANK
SEE PAGE 123 FOR REQUIRED INFORMATION.

This Federal Energy Regulatory Commission (FERC) Form 1 has been prepared in conformity with the requirements of the FERC as set forth in its applicable Uniform System of Accounts and published accounting releases, which is a comprehensive basis of accounting other than Generally Accepted Accounting Principles in the United States of America (GAAP). The following areas represent the significant differences between the Uniform System of Accounts and GAAP:

- GAAP requires that public business enterprises report certain information about operating segments in complete sets of financial statements of the enterprise and certain information about their products and services, which are not required for FERC reporting purposes.

- GAAP requires that majority-owned subsidiaries be consolidated for financial reporting purposes. FERC requires that majority-owned subsidiaries be separately reported as Investment in Subsidiary Companies, unless an appropriate waiver has been granted by the FERC.

- FERC requires that income or losses of an unusual nature and infrequent occurrence, which would significantly distort the current year's income, be recorded as extraordinary income or deductions, respectively.

- GAAP requires that removal and nuclear decommissioning costs for property that does not have an associated legal retirement obligation be presented as a regulatory liability on the Balance Sheet. These costs are presented as accumulated depreciation on the Balance Sheet for FERC reporting purposes.

- GAAP requires the regulatory assets and liabilities resulting from the implementation of ASC 740-10 (formerly SFAS No. 109) be presented as a net amount on the balance sheet. For FERC reporting purposes, these assets and liabilities are presented separately and are included in the Other Regulatory Asset and Other Regulatory Liability line items.

- GAAP requires that the current portion of regulatory assets and regulatory liabilities be reported as current assets and current liabilities, respectively, on the Balance Sheet. FERC requires that the current portion of regulatory assets and liabilities be reported as Regulatory Assets within Deferred Debits and Regulatory Liabilities within Deferred Credits, respectively.

- GAAP requires that the current portion of long-term debt and preferred stock be reported as a current liability on the Balance Sheet. FERC requires that the current portion of long-term debt and preferred stock be reported as Long-term Debt and Proprietary Capital.

- GAAP requires that any deferred costs associated with a specific debt issuance be presented as a reduction to debt on the Balance Sheet. FERC requires any Unamortized Debt Expense to be separately stated as a Deferred Debit on the Balance Sheet.

- GAAP requires that certain account balances within financial statement line items which are not in the natural position for that line item (e.g. an account within Accounts Receivable with a credit balance) be reclassed to the appropriate side of the Balance Sheet. FERC does not require certain accounts which are not in a natural position for their respective line item to be reclassed, as long as the line item in total is in its natural position.

- GAAP requires that the current portion of the provision for injuries and damages be reported as a current liability on the Balance Sheet. GAAP also requires that the current portion of the expected insurance proceeds receivable related to the provision for injuries and damages be reported as a current asset on the Balance Sheet. FERC requires that the current portion of the provision for injuries and damages be reported as 'Accumulated Provision for Injuries and Damages' and that the current portion of the related insurance receivable be reported as 'Deferred Debits'.

- GAAP requires that regulated assets that are abandoned or retired early, including the cost of the asset and its associated accumulated depreciation, be reclassified to a separate regulatory asset on the Balance Sheet. For FERC reporting purposes, those assets which have been abandoned but are still operating are maintained in their original balance sheet accounts.

- GAAP requires that the current portion of Asset Retirement Obligations be reported as current liabilities on the Balance Sheet. For FERC reporting purposes, these liabilities are not reported separately and are reflected as Asset Retirement Obligations within the Other Noncurrent Liabilities section of the Balance Sheet.

- GAAP requires service cost related to pensions and Post-Retirement Benefits Other Than Pensions (PBOP) to be reported with other compensation costs arising from services rendered by employees during the period and included in a subtotal of income from operations on the income statement. Non-service cost components are presented separately outside the subtotal of income from operations on the income statement. For FERC reporting purposes, costs related to pensions and PBOP is included in the Net Utility Operating Income of the income statement.

On March 11, 2020 the World Health Organization declared the novel strain of coronavirus (COVID-19) a global pandemic and recommended containment and mitigation measures worldwide. It is anticipated that COVID-19 will negatively impact global economies, including in the United States. The extent to which COVID-19 impacts our operations, including demand for electricity, will depend on future developments, which are highly uncertain and cannot be predicted, including new information which may emerge concerning the severity of the outbreak and the actions to contain COVID-19 or treat its impact, among others.

On March 27, 2020, the Coronavirus Aid, Relief, and Economic Security (CARES) Act (the "Act") was enacted. The CARES Act is an approximately $2 trillion emergency economic stimulus package in response to the Coronavirus outbreak, which among other things contains numerous income tax provisions. Some of these tax provisions are expected to be effective retroactively for years ending before the date of enactment. The Company is currently evaluating the implications of the Act and its impact on the financial statements and related disclosures has not yet been determined.

In December 2017, Duke Energy Carolinas re-measured its deferred tax assets and liabilities to the new federal corporate income tax rate of 21%. The result of this re-measurement was a reduction in the net deferred tax liability of approximately $2.7 billion. Based on our estimate of the amount of excess deferred income taxes (EDIT) that would be used to reduce future customer rates, we recorded an increase in regulatory liabilities of approximately $3.2 billion. The additional $740 million in regulatory liabilities was required to reflect the future revenue reduction required to return $2.4 billion of previously collected income taxes to customers. We also recorded a $740 million deferred tax asset related to the $2.4 billion regulatory liability. The accounts that were debited and (credited) in the 2017 re-measurement of deferred income taxes are reflected below (in millions):

	254	**190**	**282**	**283**	**410.2**	**182.3/253/254**	**236**
EDIT	$ (2,429)	$ (935)	$ 2,451	$ 1,200	$ 14	$ (296)	$ (5)
Gross ups	(740)	740	-	-	-	-	-
Total	**$ (3,169)**	**$ (195)**	**$ 2,451**	**$ 1,200**	**$ 14**	**$ (296)**	**$ (5)**

	NC Retail	**SC Retail**	**Wholesale**	**Total**
EDIT Detail by Customer	$ (1,641)	$ (565)	$ (223)	$ (2,429)

In December 2018, Duke Energy Carolinas recorded adjustments to accumulated deferred income tax (ADIT) and EDIT after filing the 2017 tax return.

In 2019, Duke Energy Carolinas recorded adjustments to ADIT and EDIT for the implementation of Accounting Standards Update 2018-02-Income Statement-Reporting Comprehensive Income.

As of December 2018 and 2019, the cumulative re-measurement, prior to amortization, is shown below (in millions):

	2018			2019		
Accounts	**EDIT**	**Gross ups**	**Total**	**EDIT**	**Gross ups**	**Total**
254	$(2,466)	$(751)	$(3,217)	$(2,468)	$(752)	$(3,220)
190	(992)	751	(241)	(990)	752	(238)
282	2,488	-	2,488	2,488	-	2,488
283	1,248	-	1,248	1,248	-	1,248
410.2	15	-	15	15	-	15
182.3/253/254	(288)	-	(288)	(288)	-	(288)
236	(5)	-	(5)	(5)	-	(5)
Total	**$-**	**$-**	**$-**	**$-**	**$-**	**$-**

EDIT Detail by Customer	**12/31/2018**	**12/31/2019**
NC Retail	$ (1,666)	$ (1,668)
SC Retail	(574)	(574)
Wholesale	(226)	(226)
Total	**$ (2,466)**	**$ (2,468)**

The amount of EDIT that is considered protected and unprotected as of December 31, 2019 and 2018 is reflected below (in millions):

EDIT Category	**12/31/18**	**12/31/19**
Protected:		
NC Retail	$ (914)	$ (893)
SC Retail	(315)	(312)
Wholesale	(124)	(124)
Unprotected:		
NC Retail	(752)	(775)
SC Retail	(259)	(262)
Wholesale	(102)	(102)
Total	**$ (2,466)**	**$ (2,468)**

On June 22, 2018 Duke Energy Carolinas received a regulatory order from the North Carolina Utilities Commission directing the company to maintain the EDIT in a regulatory liability for the next 3 years or until their next general rate case proceeding, whichever is sooner. On May 21, 2019 Duke Energy Carolinas received a regulatory order from The Public Service Commission of South Carolina directing the company to amortize EDIT liabilities as shown in the table below. The reduction in the EDIT regulatory liability will offset against account 411.1, the account to which the original re-measurement of deferred income taxes was recorded in December 2017. The estimated amortization period based on regulatory orders, and the accounts that the amortization will be reported in is reflected below:

EDIT Category by Jurisdiction	**Amortization Period**	**2018 Amortization Amounts**	**2019 Amortization Amounts**
411.1			
Protected:			
NC Retail	In accordance with ARAM, which is generally between 25 and 50 years	$ -	$ -
SC Retail	In accordance with ARAM, which is generally between 25 and 50 years	-	4.6
Wholesale - Production FERC	In accordance with ARAM, which is generally between 25 and 50 years	-	2.8
Wholesale -Transmission FERC	In accordance with ARAM, which is generally between 25 and 50 years	-	-
Unprotected:			
NC Retail	Rate case in process	-	-
SC Retail	20 years for Unprotected PPE, 5 years for Unprotected Non-PPE, both beginning 6/1/2019	-	12.1
Wholesale - Production FERC	20 years for Unprotected PPE, 5 years for Unprotected Non-PPE, both beginning 1/1/2019	-	8.8
Wholesale - Transmission FERC	In accordance with FERC Order 864.	-	-
Total Amortization		**$-**	**$28.3**

In the table above, ARAM refers to the average rate assumption method.

The Combined Notes To Consolidated Financial Statements below are as published in the fourth quarter ended December 31, 2019 Form 10-K (includes Duke Energy Carolinas, LLC, Duke Energy Progress, LLC, Duke Energy Florida, LLC, Duke Energy Ohio, Inc., Duke Energy Indiana, LLC and Piedmont Natural Gas Company, Inc.) filed on February 20, 2020. See "Index to the Combined Notes to Consolidated Financial Statements" for a listing of applicable notes for Duke Energy Carolinas, LLC.

Index to Combined Notes To Consolidated Financial Statements

The notes to the consolidated financial statements are a combined presentation. The following table indicates the registrants to which the notes apply.

	Applicable Notes																									
Registrant	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**
Duke Energy	•	•	•	•	•	•	•	•	•	•	•	•	•		•	•	•	•	•	•	•	•	•	•	•	•	•
Duke Energy Carolinas	•		•	•	•	•	•		•	•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Progress Energy	•		•	•	•	•	•			•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Progress	•		•	•	•	•	•			•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Florida	•		•	•	•	•	•			•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Duke Energy Ohio	•		•	•	•	•	•			•	•	•		•	•		•	•	•		•	•	•	•	•	•	•
Duke Energy Indiana	•		•	•	•	•	•		•	•	•	•		•	•	•	•	•	•		•	•	•	•	•	•	•
Piedmont	•	•	•	•	•	•	•			•	•	•	•	•	•		•		•		•	•	•	•	•	•	•

Tables within the notes may not sum across due to (i) Progress Energy's consolidation of Duke Energy Progress, Duke Energy Florida and other subsidiaries that are not registrants and (ii) subsidiaries that are not registrants but included in the consolidated Duke Energy balances.

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Nature of Operations and Basis of Consolidation

Duke Energy is an energy company headquartered in Charlotte, North Carolina, subject to regulation by the FERC and other regulatory agencies listed below. Duke Energy operates in the U.S. primarily through its direct and indirect subsidiaries. Certain Duke Energy subsidiaries are also subsidiary registrants, including Duke Energy Carolinas; Progress Energy; Duke Energy Progress; Duke Energy Florida; Duke Energy Ohio; Duke Energy Indiana and Piedmont. When discussing Duke Energy's consolidated financial information, it necessarily includes the results of its separate Subsidiary Registrants, which along with Duke Energy, are collectively referred to as the Duke Energy Registrants.

The information in these combined notes relates to each of the Duke Energy Registrants as noted in the Index to Combined Notes to Consolidated Financial Statements. However, none of the Subsidiary Registrants make any representation as to information related solely to Duke Energy or the Subsidiary Registrants of Duke Energy other than itself.

These Consolidated Financial Statements include, after eliminating intercompany transactions and balances, the accounts of the Duke Energy Registrants and subsidiaries or VIEs where the respective Duke Energy Registrants have control. See Note 18 for additional information on VIEs. These Consolidated Financial Statements also reflect the Duke Energy Registrants' proportionate share of certain jointly owned generation and transmission facilities. See Note 9 for additional information on joint ownership. Substantially all of the Subsidiary Registrants' operations qualify for regulatory accounting.

Duke Energy Carolinas is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Carolinas is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Progress Energy is a public utility holding company, which conducts operations through its wholly owned subsidiaries, Duke Energy Progress and Duke Energy Florida. Progress Energy is subject to regulation by FERC and other regulatory agencies listed below.

Duke Energy Progress is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of North Carolina and South Carolina. Duke Energy Progress is subject to the regulatory provisions of the NCUC, PSCSC, NRC and FERC.

Duke Energy Florida is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Florida. Duke Energy Florida is subject to the regulatory provisions of the FPSC, NRC and FERC.

Duke Energy Ohio is a regulated public utility primarily engaged in the transmission and distribution of electricity in portions of Ohio and Kentucky, the generation and sale of electricity in portions of Kentucky and the transportation and sale of natural gas in portions of Ohio and Kentucky. Duke Energy Ohio conducts competitive auctions for retail electricity supply in Ohio whereby the energy price is recovered from retail customers and recorded in Operating Revenues on the Consolidated Statements of Operations and Comprehensive Income. Operations in Kentucky are conducted through its wholly owned subsidiary, Duke Energy Kentucky. References herein to Duke Energy Ohio collectively include Duke Energy Ohio and its subsidiaries, unless otherwise noted. Duke Energy Ohio is subject to the regulatory provisions of the PUCO, KPSC and FERC.

Duke Energy Indiana is a regulated public utility primarily engaged in the generation, transmission, distribution and sale of electricity in portions of Indiana. Duke Energy Indiana is subject to the regulatory provisions of the IURC and FERC.

Piedmont is a regulated public utility primarily engaged in the distribution of natural gas in portions of North Carolina, South Carolina and Tennessee. Piedmont is subject to the regulatory provisions of the NCUC, PSCSC, TPUC and FERC.

Certain prior year amounts have been reclassified to conform to the current year presentation.

Other Current Assets and Liabilities

The following table provides a description of amounts included in Other within Current Assets or Current Liabilities that exceed 5% of total Current Assets or Current Liabilities on the Duke Energy Registrants' Consolidated Balance Sheets at either December 31, 2019, or 2018.

		December 31,	
(in millions)	**Location**	**2019**	**2018**
Duke Energy			
Taxes receivable	Current Assets	**$ 357**	$ 729
Accrued compensation	Current Liabilities	**862**	793
Duke Energy Carolinas			
Accrued compensation	Current Liabilities	**$ 271**	$ 251
Other accrued liabilities	Current Liabilities	**147**	55
Progress Energy			
Customer deposits	Current Liabilities	**$ 354**	$ 345
Duke Energy Florida			
Customer deposits	Current Liabilities	**$ 209**	$ 208
Other accrued liabilities	Current Liabilities	**89**	85
Duke Energy Indiana			
Income taxes receivable	Current Assets	**$ 44**	$ 9
Customer deposits	Current Liabilities	**49**	47

Discontinued Operations

Duke Energy has elected to present cash flows of discontinued operations combined with cash flows of continuing operations. Unless otherwise noted, the notes to these consolidated financial statements exclude amounts related to discontinued operations for all periods presented. See Note 2 for additional information.

Amounts Attributable to Controlling Interests

For the years ended December 31, 2019, 2018 and 2017, the Income (Loss) From Discontinued Operations, net of tax on Duke Energy's Consolidated Statements of Operations is entirely attributable to controlling interest.

Noncontrolling Interest

Duke Energy maintains a controlling financial interest in certain less-than wholly owned non-regulated subsidiaries. As a result, Duke Energy consolidates these subsidiaries and presents the third-party investors' portion of Duke Energy's net income (loss), net assets and comprehensive income (loss) as noncontrolling interest. Noncontrolling interest is included as a component of equity on the Consolidated Balance Sheet.

Several operating agreements of Duke Energy's subsidiaries with noncontrolling interest are subject to allocations of tax attributes and cash flows in accordance with contractual agreements that vary throughout the lives of the subsidiaries. Therefore, Duke Energy and the other investors' (the owners) interests in the subsidiaries are not fixed, and the subsidiaries apply the HLBV method in allocating income or loss and other comprehensive income or loss (all measured on a pretax basis) to the owners. The HLBV method measures the amounts that each owner would hypothetically claim at each balance sheet reporting date, including tax benefits realized by the owners, upon a hypothetical liquidation of the subsidiary at the net book value of its underlying assets. The change in the amount that each owner would hypothetically receive at the reporting date compared to the amount it would have received on the previous reporting date represents the amount of income or loss allocated to each owner for the reporting period. During 2019, Duke Energy received $428 million for the sale of noncontrolling interests to tax equity members subject to the HLBV method for projects totaling 718 MW in nameplate capacity. Duke Energy allocated approximately $165 million of losses to noncontrolling tax equity members utilizing the HLBV method for the year ended December 31, 2019.

Other operating agreements of Duke Energy's subsidiaries with noncontrolling interest allocate profit and loss based on their pro rata shares of the ownership interest in the respective subsidiary. Therefore, Duke Energy allocates net income or loss and other comprehensive income or loss of these subsidiaries to the owners based on their pro rata shares.

During the third quarter of 2019, Duke Energy completed a sale of minority interest in a portion of certain renewable assets to John Hancock. John Hancock's ownership interest in the assets represents a noncontrolling interest. See Note 2 for additional information on the sale.

Significant Accounting Policies

Use of Estimates

In preparing financial statements that conform to GAAP, the Duke Energy Registrants must make estimates and assumptions that affect the reported amounts of assets and liabilities, the reported amounts of revenues and expenses and the disclosure of contingent assets and liabilities at the date of the financial statements. Actual results could differ from those estimates.

Regulatory Accounting

The majority of the Duke Energy Registrants' operations are subject to price regulation for the sale of electricity and natural gas by state utility commissions or FERC. When prices are set on the basis of specific costs of the regulated operations and an effective franchise is in place such that sufficient natural gas or electric services can be sold to recover those costs, the Duke Energy Registrants apply regulatory accounting. Regulatory accounting changes the timing of the recognition of costs or revenues relative to a company that does not apply regulatory accounting. As a result, regulatory assets and regulatory liabilities are recognized on the Consolidated Balance Sheets. Regulatory assets and liabilities are amortized consistent with the treatment of the related cost in the ratemaking process. See Note 4 for further information.

Regulatory accounting rules also require recognition of a disallowance (also called "impairment") loss if it becomes probable that part of the cost of a plant under construction (or a recently completed plant or an abandoned plant) will be disallowed for ratemaking purposes and a reasonable estimate of the amount of the disallowance can be made. For example, if a cost cap is set for a plant still under construction, the amount of the disallowance is a result of a judgment as to the ultimate cost of the plant. These disallowances can require judgments on allowed future rate recovery.

When it becomes probable that regulated generation, transmission or distribution assets will be abandoned, the cost of the asset is removed from plant in service. The value that may be retained as a regulatory asset on the balance sheet for the abandoned property is dependent upon amounts that may be recovered through regulated rates, including any return. As such, an impairment charge could be partially or fully offset by the establishment of a regulatory asset if rate recovery is probable. The impairment charge for a disallowance of costs for regulated plants under construction, recently completed or abandoned is based on discounted cash flows.

The Duke Energy Registrants utilize cost-tracking mechanisms, commonly referred to as fuel adjustment clauses or PGA clauses. These clauses allow for the recovery of fuel and fuel-related costs, portions of purchased power, natural gas costs and hedging costs through surcharges on customer rates. The difference between the costs incurred and the surcharge revenues is recorded either as an adjustment to Operating Revenues, Operating Expenses – Fuel used in electric generation or Operating Expenses – Cost of natural gas on the Consolidated Statements of Operations, with an off-setting impact on regulatory assets or liabilities.

Cash, Cash Equivalents and Restricted Cash

All highly liquid investments with maturities of three months or less at the date of acquisition are considered cash equivalents. Duke Energy, Progress Energy and Duke Energy Florida have restricted cash balances related primarily to collateral assets, escrow deposits and VIEs. See Note 18 for additional information. Restricted cash amounts are included in Other within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets. The following table presents the components of cash, cash equivalents and restricted cash included in the Consolidated Balance Sheets.

	December 31, 2019			December 31, 2018		
	Duke Energy	Progress Energy	Duke Energy Florida	Duke Energy	Progress Energy	Duke Energy Florida
Current Assets						
Cash and cash equivalents	$ 311	$ 48	$ 17	$ 442	$ 67	$ 36
Other	222	39	39	141	39	39
Other Noncurrent Assets						
Other	40	39	—	8	6	—
Total cash, cash equivalents and restricted cash	$ 573	$ 126	$ 56	$ 591	$ 112	$ 75

Inventory

Inventory related to regulated operations is valued at historical cost. Inventory related to nonregulated operations is valued at the lower of cost or market. Inventory is charged to expense or capitalized to property, plant and equipment when issued, primarily using the average cost method. Excess or obsolete inventory is written-down to the lower of cost or net realizable value. Once inventory has been written-down, it creates a new cost basis for the inventory that is not subsequently written-up. Provisions for inventory write-offs were not material at December 31, 2019, and 2018, respectively. The components of inventory are presented in the tables below.

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Materials and supplies	$ 2,297	$ 768	$ 1,038	$ 686	$ 351	$ 79	$ 318	$ 5
Coal	586	187	186	138	48	15	198	—
Natural gas, oil and other	349	41	199	110	90	41	1	67
Total inventory	$ 3,232	$ 996	$ 1,423	$ 934	$ 489	$ 135	$ 517	$ 72

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Materials and supplies	$ 2,238	$ 731	$ 1,049	$ 734	$ 315	$ 84	$ 312	$ 2
Coal	491	175	192	106	86	14	109	—
Natural gas, oil and other	355	42	218	114	103	28	1	68
Total inventory	$ 3,084	$ 948	$ 1,459	$ 954	$ 504	$ 126	$ 422	$ 70

Investments in Debt and Equity Securities

The Duke Energy Registrants classify investments in equity securities as FV-NI and investments in debt securities as AFS. Both categories are recorded at fair value on the Consolidated Balance Sheets. Realized and unrealized gains and losses on securities classified as FV-NI are reported through net income. Unrealized gains and losses for debt securities classified as AFS are included in AOCI until realized, except OTTIs that are included in earnings immediately. At the time gains and losses for debt securities are realized, they are reported through net income. For certain investments of regulated operations, such as substantially all of the NDTF, realized and unrealized gains and losses (including any OTTIs) on debt securities are recorded as a regulatory asset or liability. The credit loss portion of debt securities of nonregulated operations are included in earnings. Investments in debt and equity securities are classified as either current or noncurrent based on management's intent and ability to sell these securities, taking into consideration current market liquidity. See Note 16 for further information.

Goodwill

Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont perform annual goodwill impairment tests as of August 31 each year at the reporting unit level, which is determined to be a business segment or one level below. Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont update these tests between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. See Note 12 for further information.

Intangible Assets

Intangible assets are included in Other in Other Noncurrent Assets on the Consolidated Balance Sheets. Generally, intangible assets are amortized using an amortization method that reflects the pattern in which the economic benefits of the intangible asset are consumed or on a straight-line basis if that pattern is not readily determinable. Amortization of intangibles is reflected in Depreciation and amortization on the Consolidated Statements of Operations. Intangible assets are subject to impairment testing and if impaired, the carrying value is accordingly reduced.

Emission allowances permit the holder of the allowance to emit certain gaseous byproducts of fossil fuel combustion, including SO_2 and NO_X. Allowances are issued by the EPA at zero cost and may also be bought and sold via third-party transactions. Allowances allocated to or acquired by the Duke Energy Registrants are held primarily for consumption. Carrying amounts for emission allowances are based on the cost to acquire the allowances. Emission allowances are expensed to Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.

RECs are used to measure compliance with renewable energy standards and are held primarily for consumption. See Note 12 for further information.

Long-Lived Asset Impairments

The Duke Energy Registrants evaluate long-lived assets, excluding goodwill, for impairment when circumstances indicate the carrying value of those assets may not be recoverable. An impairment exists when a long-lived asset's carrying value exceeds the estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. If the carrying value of the long-lived asset is not recoverable based on these estimated future undiscounted cash flows, the carrying value of the asset is written-down to its then-current estimated fair value and an impairment charge is recognized.

The Duke Energy Registrants assess fair value of long-lived assets using various methods, including recent comparable third-party sales, internally developed discounted cash flow analysis and analysis from outside advisors. Triggering events to reassess cash flows may include, but are not limited to, significant changes in commodity prices, the condition of an asset or management's interest in selling the asset.

Equity Method Investment Impairments

Investments in affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method. Equity method investments are assessed for impairment whenever events or changes in circumstances indicate that the carrying amount of the investment may not be recoverable. If the decline in value is considered to be other than temporary, the investment is written down to its estimated fair value, which establishes a new cost basis in the investment.

Impairment assessments use a discounted cash flow income approach and include consideration of the severity and duration of any decline in the fair value of the investments. The estimated cash flows may be based on alternative expected outcomes that are probability weighted. Key inputs that involve estimates and significant management judgment include cash flow projections, selection of a discount rate, probability weighting of potential outcomes, and whether any decline in value is considered temporary.

Property, Plant and Equipment

Property, plant and equipment are stated at the lower of depreciated historical cost net of any disallowances or fair value, if impaired. The Duke Energy Registrants capitalize all construction-related direct labor and material costs, as well as indirect construction costs such as general engineering, taxes and financing costs. See "Allowance for Funds Used During Construction and Interest Capitalized" for information on capitalized financing costs. Costs of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. The cost of repairs, replacements and major maintenance projects, which do not extend the useful life or increase the expected output of the asset, are expensed as incurred. Depreciation is generally computed over the estimated useful life of the asset using the composite straight-line method. Depreciation studies are conducted periodically to update composite rates and are approved by state utility commissions and/or the FERC when required. The composite weighted average depreciation rates, excluding nuclear fuel, are included in the table that follows.

	Years Ended December 31,		
	2019	**2018**	**2017**
Duke Energy	**3.1%**	3.0%	2.8%
Duke Energy Carolinas	**2.8%**	2.8%	2.8%
Progress Energy	**3.1%**	2.9%	2.6%
Duke Energy Progress	**3.1%**	2.9%	2.6%
Duke Energy Florida	**3.1%**	3.0%	2.8%
Duke Energy Ohio	**2.6%**	2.8%	2.8%
Duke Energy Indiana	**3.3%**	3.3%	3.0%
Piedmont	**2.4%**	2.5%	2.3%

In general, when the Duke Energy Registrants retire regulated property, plant and equipment, the original cost plus the cost of retirement, less salvage value and any depreciation already recognized, is charged to accumulated depreciation. However, when it becomes probable the asset will be retired substantially in advance of its original expected useful life or is abandoned, the cost of the asset and the corresponding accumulated depreciation is recognized as a separate asset. If the asset is still in operation, the net amount is classified as Generation facilities to be retired, net on the Consolidated Balance Sheets. If the asset is no longer operating, the net amount is classified in Regulatory assets on the Consolidated Balance Sheets if deemed recoverable (see discussion of long-lived asset impairments above). The carrying value of the asset is based on historical cost if the Duke Energy Registrants are allowed to recover the remaining net book value and a return equal to at least the incremental borrowing rate. If not, an impairment is recognized to the extent the net book value of the asset exceeds the present value of future revenues discounted at the incremental borrowing rate.

When the Duke Energy Registrants sell entire regulated operating units, or retire or sell nonregulated properties, the original cost and accumulated depreciation and amortization balances are removed from Property, Plant and Equipment on the Consolidated Balance Sheets. Any gain or loss is recorded in earnings, unless otherwise required by the applicable regulatory body. See Note 11 for additional information.

Nuclear Fuel

Nuclear fuel is classified as Property, Plant and Equipment on the Consolidated Balance Sheets.

Nuclear fuel in the front-end fuel processing phase is considered work in progress and not amortized until placed in service. Amortization of nuclear fuel is included within Fuel used in electric generation and purchased power on the Consolidated Statements of Operations. Amortization is recorded using the units-of-production method.

Allowance for Funds Used During Construction and Interest Capitalized

For regulated operations, the debt and equity costs of financing the construction of property, plant and equipment are reflected as AFUDC and capitalized as a component of the cost of property, plant and equipment. AFUDC equity is reported on the Consolidated Statements of Operations as non-cash income in Other income and expenses, net. AFUDC debt is reported as a non-cash offset to Interest Expense. After construction is completed, the Duke Energy Registrants are permitted to recover these costs through their inclusion in rate base and the corresponding subsequent depreciation or amortization of those regulated assets.

AFUDC equity, a permanent difference for income taxes, reduces the ETR when capitalized and increases the ETR when depreciated or amortized. See Note 24 for additional information.

For nonregulated operations, interest is capitalized during the construction phase with an offsetting non-cash credit to Interest Expense on the Consolidated Statements of Operations.

Asset Retirement Obligations

AROs are recognized for legal obligations associated with the retirement of property, plant and equipment. Substantially all AROs are related to regulated operations. When recording an ARO, the present value of the projected liability is recognized in the period in which it is incurred, if a reasonable estimate of fair value can be made. The liability is accreted over time. For operating plants, the present value of the liability is added to the cost of the associated asset and depreciated over the remaining life of the asset. For retired plants, the present value of the liability is recorded as a regulatory asset unless determined not to be probable of recovery.

The present value of the initial obligation and subsequent updates are based on discounted cash flows, which include estimates regarding timing of future cash flows, selection of discount rates and cost escalation rates, among other factors. These estimates are subject to change. Depreciation expense is adjusted prospectively for any changes to the carrying amount of the associated asset. The Duke Energy Registrants receive amounts to fund the cost of the ARO for regulated operations through a combination of regulated revenues and earnings on the NDTF. As a result, amounts recovered in regulated revenues, earnings on the NDTF, accretion expense and depreciation of the associated asset are netted and deferred as a regulatory asset or liability.

Obligations for nuclear decommissioning are based on site-specific cost studies. Duke Energy Carolinas and Duke Energy Progress assume prompt dismantlement of the nuclear facilities after operations are ceased. In 2019, Duke Energy Florida entered into an agreement for the accelerated decommissioning of Crystal River Unit 3. See Note 4 for more information. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida also assume that spent fuel will be stored on-site until such time that it can be transferred to a yet to be built DOE facility.

Obligations for closure of ash basins are based upon discounted cash flows of estimated costs for site-specific plans, if known, or probability weightings of the potential closure methods if the closure plans are under development and multiple closure options are being considered and evaluated on a site-by-site basis. See Note 10 for additional information.

Revenue Recognition

Duke Energy recognizes revenue as customers obtain control of promised goods and services in an amount that reflects consideration expected in exchange for those goods or services. Generally, the delivery of electricity and natural gas results in the transfer of control to customers at the time the commodity is delivered and the amount of revenue recognized is equal to the amount billed to each customer, including estimated volumes delivered when billings have not yet occurred. See Note 19 for further information.

Derivatives and Hedging

Derivative and non-derivative instruments may be used in connection with commodity price and interest rate activities, including swaps, futures, forwards and options. All derivative instruments, except those that qualify for the NPNS exception, are recorded on the Consolidated Balance Sheets at fair value. Qualifying derivative instruments may be designated as either cash flow hedges or fair value hedges. Other derivative instruments (undesignated contracts) either have not been designated or do not qualify as hedges. The effective portion of the change in the fair value of cash flow hedges is recorded in AOCI. The effective portion of the change in the fair value of a fair value hedge is offset in net income by changes in the hedged item. For activity subject to regulatory accounting, gains and losses on derivative contracts are reflected as regulatory assets or liabilities and not as other comprehensive income or current period income. As a result, changes in fair value of these derivatives have no immediate earnings impact.

Formal documentation, including transaction type and risk management strategy, is maintained for all contracts accounted for as a hedge. At inception and at least every three months thereafter, the hedge contract is assessed to see if it is highly effective in offsetting changes in cash flows or fair values of hedged items.

See Note 15 for further information.

Captive Insurance Reserves

Duke Energy has captive insurance subsidiaries that provide coverage, on an indemnity basis, to the Subsidiary Registrants as well as certain third parties, on a limited basis, for financial losses, primarily related to property, workers' compensation and general liability. Liabilities include provisions for estimated losses incurred but not reported (IBNR), as well as estimated provisions for known claims. IBNR reserve estimates are primarily based upon historical loss experience, industry data and other actuarial assumptions. Reserve estimates are adjusted in future periods as actual losses differ from experience.

Duke Energy, through its captive insurance entities, also has reinsurance coverage with third parties for certain losses above a per occurrence and/or aggregate retention. Receivables for reinsurance coverage are recognized when realization is deemed probable.

Unamortized Debt Premium, Discount and Expense

Premiums, discounts and expenses incurred with the issuance of outstanding long-term debt are amortized over the term of the debt issue. The gain or loss on extinguishment associated with refinancing higher-cost debt obligations in the regulated operations is amortized over the remaining life of the original instrument. Amortization expense is recorded as Interest Expense in the Consolidated Statements of Operations and is reflected as Depreciation, amortization and accretion within Net cash provided by operating activities on the Consolidated Statements of Cash Flows.

Premiums, discounts and expenses are presented as an adjustment to the carrying value of the debt amount and included in Long-Term Debt on the Consolidated Balance Sheets presented.

Preferred Stock

Preferred stock is reviewed to determine the appropriate balance sheet classification and embedded features, such as call options, are evaluated to determine if they should be bifurcated and accounted for separately. Costs directly related to the issuance of preferred stock is recorded as a reduction of the proceeds received. The liability for the dividend is recognized when declared. The accumulated dividends on the cumulative preferred stock is recognized to net income available to Duke Energy Corporation in the EPS calculation. See Note 20 for further information.

Loss Contingencies and Environmental Liabilities

Contingent losses are recorded when it is probable a loss has occurred and can be reasonably estimated. When a range of the probable loss exists and no amount within the range is a better estimate than any other amount, the minimum amount in the range is recorded. Unless otherwise required by GAAP, legal fees are expensed as incurred.

Environmental liabilities are recorded on an undiscounted basis when environmental remediation or other liabilities become probable and can be reasonably estimated. Environmental expenditures related to past operations that do not generate current or future revenues are expensed. Environmental expenditures related to operations that generate current or future revenues are expensed or capitalized, as appropriate. Certain environmental expenditures receive regulatory accounting treatment and are recorded as regulatory assets.

See Notes 4 and 5 for further information.

Pension and Other Post-Retirement Benefit Plans

Duke Energy maintains qualified, non-qualified and other post-retirement benefit plans. Eligible employees of the Subsidiary Registrants participate in the respective qualified, non-qualified and other post-retirement benefit plans and the Subsidiary Registrants are allocated their proportionate share of benefit costs. See Note 23 for further information, including significant accounting policies associated with these plans.

Severance and Special Termination Benefits

Duke Energy has severance plans under which in general, the longer a terminated employee worked prior to termination the greater the amount of severance benefits. A liability for involuntary severance is recorded once an involuntary severance plan is committed to by management if involuntary severances are probable and can be reasonably estimated. For involuntary severance benefits incremental to its ongoing severance plan benefits, the fair value of the obligation is expensed at the communication date if there are no future service requirements or over the required future service period. Duke Energy also offers special termination benefits under voluntary severance programs. Special termination benefits are recorded immediately upon employee acceptance absent a significant retention period. Otherwise, the cost is recorded over the remaining service period. Employee acceptance of voluntary severance benefits is determined by management based on the facts and circumstances of the benefits being offered. See Note 21 for further information.

Guarantees

If necessary, liabilities are recognized at the time of issuance or material modification of a guarantee for the estimated fair value of the obligation it assumes. Fair value is estimated using a probability-weighted approach. The obligation is reduced over the term of the guarantee or related contract in a systematic and rational method as risk is reduced. Any additional contingent loss for guarantee contracts subsequent to the initial recognition of a liability is accounted for and recognized at the time a loss is probable and can be reasonably estimated. See Note 8 for further information.

Stock-Based Compensation

Stock-based compensation represents costs related to stock-based awards granted to employees and Board of Directors members. Duke Energy recognizes stock-based compensation based upon the estimated fair value of awards, net of estimated forfeitures at the date of issuance. The recognition period for these costs begins at either the applicable service inception date or grant date and continues throughout the requisite service period. Compensation cost is recognized as expense or capitalized as a component of property, plant and equipment. See Note 22 for further information.

Income Taxes

Duke Energy and its subsidiaries file a consolidated federal income tax return and other state and foreign jurisdictional returns. The Subsidiary Registrants are parties to a tax-sharing agreement with Duke Energy. Income taxes recorded represent amounts the Subsidiary Registrants would incur as separate C-Corporations. Deferred income taxes have been provided for temporary differences between GAAP and tax bases of assets and liabilities because the differences create taxable or tax-deductible amounts for future periods. ITCs associated with regulated operations are deferred and amortized as a reduction of income tax expense over the estimated useful lives of the related properties.

Accumulated deferred income taxes are valued using the enacted tax rate expected to apply to taxable income in the periods in which the deferred tax asset or liability is expected to be settled or realized. In the event of a change in tax rates, deferred tax assets and liabilities are remeasured as of the enactment date of the new rate. To the extent that the change in the value of the deferred tax represents an obligation to customers, the impact of the remeasurement is deferred to a regulatory liability. Remaining impacts are recorded in income from continuing operations. If Duke Energy's estimate of the tax effect of reversing temporary differences is not reflective of actual outcomes, is modified to reflect new developments or interpretations of the tax law, revised to incorporate new accounting principles, or changes in the expected timing or manner of the reversal then Duke Energy's results of operations could be impacted.

Tax-related interest and penalties are recorded in Interest Expense and Other Income and Expenses, net in the Consolidated Statements of Operations.

See Note 24 for further information.

Accounting for Renewable Energy Tax Credits

When Duke Energy receives ITCs on wind or solar facilities, it reduces the basis of the property recorded on the Consolidated Balance Sheets by the amount of the ITC and, therefore, the ITC benefit is ultimately recognized in the statement of operations through reduced depreciation expense. Additionally, certain tax credits and government grants result in an initial tax depreciable base in excess of the book carrying value by an amount equal to one half of the ITC. Deferred tax benefits are recorded as a reduction to income tax expense in the period that the basis difference is created.

Duke Energy receives PTCs on wind facilities that are recognized as electricity is produced.

Excise Taxes

Certain excise taxes levied by state or local governments are required to be paid even if not collected from the customer. These taxes are recognized on a gross basis. Taxes for which Duke operates merely as a collection agent for the state and local government are accounted for on a net basis. Excise taxes accounted for on a gross basis within both Operating Revenues and Property and other taxes in the Consolidated Statements of Operations were as follows.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Duke Energy	**$ 421**	$ 405	$ 376
Duke Energy Carolinas	**39**	35	36
Progress Energy	**256**	241	220
Duke Energy Progress	**21**	19	19
Duke Energy Florida	**235**	222	201
Duke Energy Ohio	**101**	105	98
Duke Energy Indiana	**23**	22	20
Piedmont	**2**	2	2

Dividend Restrictions and Unappropriated Retained Earnings

Duke Energy does not have any legal, regulatory or other restrictions on paying common stock dividends to shareholders. However, as further described in Note 4, Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, Duke Energy Indiana and Piedmont have restrictions on paying dividends or otherwise advancing funds to Duke Energy due to conditions established by regulators in conjunction with merger transaction approvals. At December 31, 2019, and 2018, an insignificant amount of Duke Energy's consolidated Retained earnings balance represents undistributed earnings of equity method investments.

New Accounting Standards

Except as noted below, the new accounting standards adopted for 2019, 2018 and 2017 had no material impact on the presentation or results of operations, cash flows or financial position of the Duke Energy Registrants.

Leases. In February 2016, the FASB issued revised accounting guidance for leases. The core principle of this guidance is that a lessee should recognize the assets and liabilities that arise from leases on the balance sheet. This resulted in a material impact on the presentation for the statement of financial position of the Duke Energy Registrants for the period ended December 31, 2019, and an immaterial impact to the Duke Energy Registrants' results of operations and cash flows for the year ended December 31, 2019.

Duke Energy elected the modified retrospective method of adoption effective January 1, 2019. Under the modified retrospective method of adoption, prior year reported results are not restated. For adoption, Duke Energy elected to apply the following practical expedients:

Practical Expedient	Description
Package of transition practical expedients (for leases commenced prior to adoption date and must be adopted as a package)	Do not need to 1) reassess whether any expired or existing contracts are/or contain leases, 2) reassess the lease classification for any expired or existing leases and 3) reassess initial direct costs for any existing leases.
Short-term lease expedient (elect by class of underlying asset)	Elect as an accounting policy to not apply the recognition requirements to short-term leases by asset class.
Lease and non-lease components (elect by class of underlying asset)	Elect as an accounting policy to not separate non-lease components from lease components and instead account for each lease and associated non-lease component as a single lease component by asset class.
Hindsight expedient (when determining lease term)	Elect to use hindsight to determine the lease term.
Existing and expired land easements not previously accounted for as leases	Elect to not evaluate existing or expired easements under the new guidance and carry forward current accounting treatment.
Comparative reporting requirements for initial adoption	Elect to apply transition requirements at adoption date, recognize cumulative effect adjustment to retained earnings in period of adoption and not apply the new requirements to comparative periods, including disclosures.
Lessor expedient (elect by class of underlying asset)	Elect as an accounting policy to aggregate non-lease components with the related lease component when specified conditions are met by asset class. Account for the combined component based on its predominant characteristic (revenue or operating lease).

Duke Energy evaluated the financial statement impact of adopting the standard and monitored industry implementation issues. Under agreements considered leases, where Duke Energy is the lessee, for the use of certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land, office space and PPAs are now recognized on the balance sheet. The Duke Energy Registrants did not have a material change to the financial statements from the adoption of the new standard for contracts where it is the lessor. See Note 6 for further information.

The following new accounting standard has been issued but not yet adopted by the Duke Energy Registrants as of December 31, 2019.

Credit Losses. In June 2016, the FASB issued new accounting guidance for credit losses. This guidance establishes a new impairment model applicable to certain financial assets, including trade and other receivables, net investments in leases, and debt securities classified as held-for-sale investments. The model also applies to financial guarantees.

For Duke Energy, the guidance is effective for interim and annual periods beginning January 1, 2020. This guidance will be applied using a modified retrospective approach. Under the modified retrospective approach of adoption, prior year reported results are not restated and a cumulative-effect adjustment is recorded to retained earnings at January 1, 2020.

Upon adoption, Duke Energy will recognize an allowance for credit losses based on management's estimate of losses expected to be incurred over the lives of certain assets or guarantees. Duke Energy expects the impacts of this standard to be driven by the reserve for credit losses on financial guarantees, trade and other receivables, and insurance receivables. Duke Energy does not intend to adopt any practical expedients.

Duke Energy currently expects to record a reserve for credit losses as shown in approximate amounts in the table below:

	December 31, 2019					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Piedmont
Total pretax impact to Retained Earnings	$ 120	$ 16	$ 2	$ 1	$ 1	$ 1

In addition to the reserve for credit losses, Duke Energy expects additional disclosures on management's evaluation of credit risks inherent in financial assets and how management monitors credit quality, changes in expected credit losses, and the appropriateness of the allowance for credit losses on a forward-looking basis. Duke Energy also expects additional disclosures around credit losses for new investments in leases, loan commitments, and other financial instruments.

2. ACQUISITIONS AND DISPOSITIONS

ACQUISITIONS

The Duke Energy Registrants consolidate assets and liabilities from acquisitions as of the purchase date and include earnings from acquisitions in consolidated earnings after the purchase date.

2016 Acquisition of Piedmont Natural Gas

On October 3, 2016, Duke Energy acquired all outstanding common stock of Piedmont for a total cash purchase price of $5 billion and assumed Piedmont's existing long-term debt, which had a fair value of approximately $2 billion at the time of the acquisition. The acquisition provides a foundation for Duke Energy to establish a broader, long-term strategic natural gas infrastructure platform to complement its existing natural gas pipeline investments and regulated natural gas business in the Midwest. In connection with the closing of the acquisition, Piedmont became a wholly owned subsidiary of Duke Energy.

Accounting Charges Related to the Acquisition

Duke Energy incurred pretax transaction and integration costs associated with the acquisition of $84 million and $103 million for the years ended December 31, 2018, and 2017, respectively. Amounts recorded on the Consolidated Statements of Operations in 2018 and 2017 were primarily system integration costs of $78 million and $71 million, respectively, related to combining the various operational and financial systems of Duke Energy and Piedmont, including a one-time software impairment resulting from planned accounting system and process integration in 2017. A $7 million charge was recorded within Impairment Charges, with the remaining $64 million recorded within Operation, maintenance and other in 2017.

The majority of transition and integration activities were completed by the end of 2018.

DISPOSITIONS

On April 24, 2019, Duke Energy executed an agreement to sell a minority interest in a portion of certain renewable assets within the Commercial Renewables segment. The sale closed on September 6, 2019, and resulted in pretax proceeds to Duke Energy of $415 million. The portion of Duke Energy's commercial renewables energy portfolio sold includes 49% of 37 operating wind, solar and battery storage assets and 33% of 11 operating solar assets across the U.S. Duke Energy retained control of these assets, and, therefore, no gain or loss was recognized on the Consolidated Statements of Operations. The difference between the consideration received and the carrying value of the noncontrolling interest claim on net assets is $466 million, net of a tax benefit of $8 million, and was recorded in equity.

3. BUSINESS SEGMENTS

Reportable segments are determined based on information used by the chief operating decision-maker in deciding how to allocate resources and evaluate the performance of the business. Duke Energy evaluates segment performance based on segment income. Segment income is defined as income from continuing operations net of income attributable to noncontrolling interests. Segment income, as discussed below, includes intercompany revenues and expenses that are eliminated on the Consolidated Financial Statements. Certain governance costs are allocated to each segment. In addition, direct interest expense and income taxes are included in segment income.

Products and services are sold between affiliate companies and reportable segments of Duke Energy at cost. Segment assets as presented in the tables that follow exclude all intercompany assets.

Duke Energy

Duke Energy's segment structure includes the following segments: Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

The Electric Utilities and Infrastructure segment includes Duke Energy's regulated electric utilities in the Carolinas, Florida and the Midwest. The regulated electric utilities conduct operations through the Subsidiary Registrants that are substantially all regulated and, accordingly, qualify for regulatory accounting treatment. Electric Utilities and Infrastructure also includes Duke Energy's electric transmission infrastructure investments.

The Gas Utilities and Infrastructure segment includes Piedmont, Duke Energy's natural gas local distribution companies in Ohio and Kentucky, and Duke Energy's natural gas storage and midstream pipeline investments. Gas Utilities and Infrastructure's operations are substantially all regulated and, accordingly, qualify for regulatory accounting treatment.

The Commercial Renewables segment is primarily comprised of nonregulated utility-scale wind and solar generation assets located throughout the U.S. On April 24, 2019, Duke Energy executed an agreement to sell a minority interest in a portion of certain renewable assets. See Note 2 for additional information on the minority interest sale.

The remainder of Duke Energy's operations is presented as Other, which is primarily comprised of interest expense on holding company debt, unallocated corporate costs and Duke Energy's wholly owned captive insurance company, Bison. Other also includes Duke Energy's interest in NMC. See Note 13 for additional information on the investment in NMC.

Business segment information is presented in the following tables. Segment assets presented exclude intercompany assets.

	Year Ended December 31, 2019						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 22,798	$ 1,770	$ 487	$ 25,055	$ 24	$ —	$ 25,079
Intersegment Revenues	33	96	—	129	71	(200)	—
Total Revenues	$ 22,831	$ 1,866	$ 487	$ 25,184	$ 95	$ (200)	$ 25,079
Interest Expense	$ 1,345	$ 117	$ 95	$ 1,557	$ 705	$ (58)	$ 2,204
Depreciation and amortization	3,951	256	168	4,375	178	(5)	4,548
Equity in earnings (losses) of unconsolidated affiliates	9	114	(4)	119	43	—	162
Income tax expense (benefit)	785	22	(115)	692	(173)	—	519
Segment income (loss)[(a)(b)]	3,536	432	198	4,166	(452)	—	3,714
Add back noncontrolling interest[(c)]							(177)
Add back preferred stock dividend							41
Loss from discontinued operations, net of tax							(7)
Net income							$ 3,571
Capital investments expenditures and acquisitions	$ 8,263	$ 1,539	$ 1,423	$ 11,225	$ 221	$ —	$ 11,446
Segment assets	135,561	13,921	6,020	155,502	3,148	188	158,838

(a) Electric Utilities and Infrastructure includes a $27 million reduction of a prior year impairment at Citrus County CC related to the plant's cost cap. See Note 4 for additional information.

(b) Gas Utilities and Infrastructure includes an after-tax impairment charge of $19 million for the remaining investment in Constitution. See Note 13 for additional information.

(c) Includes the allocation of losses to noncontrolling tax equity members. See Note 1 for additional information.

	Year Ended December 31, 2018						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 22,242	$ 1,783	$ 477	$ 24,502	$ 19	$ —	$ 24,521
Intersegment Revenues	31	98	—	129	70	(199)	—
Total Revenues	$ 22,273	$ 1,881	$ 477	$ 24,631	$ 89	$ (199)	$ 24,521
Interest Expense	$ 1,288	$ 106	$ 88	$ 1,482	$ 657	$ (45)	$ 2,094
Depreciation and amortization	3,523	245	155	3,923	152	(1)	4,074
Equity in earnings (losses) of unconsolidated affiliates	5	27	(1)	31	52	—	83
Income tax expense (benefit)[a]	799	78	(147)	730	(282)	—	448
Segment income (loss)[b][c][d][e]	3,058	274	9	3,341	(694)	—	2,647
Add back noncontrolling interest component							(22)
Loss from discontinued operations, net of tax							19
Net income							$ 2,644
Capital investments expenditures and acquisitions	$ 8,086	$ 1,133	$ 193	$ 9,412	$ 256	$ —	$ 9,668
Segment assets	125,364	12,361	4,204	141,929	3,275	188	145,392

(a) All segments include adjustments to the December 31, 2017, estimate of the income tax effects of the Tax Act. Electric Utilities and Infrastructure includes a $24 million expense, Gas Utilities and Infrastructure includes a $1 million expense, Commercial Renewables includes a $3 million benefit and Other includes a $2 million benefit. See Note 24 for additional information.

(b) Electric Utilities and Infrastructure includes after-tax regulatory and legislative impairment charges of $202 million related to rate case orders, settlements or other actions of regulators or legislative bodies and an after-tax impairment charge of $46 million related to the Citrus County CC at Duke Energy Florida. See Note 4 for additional information.

(c) Gas Utilities and Infrastructure includes an after-tax impairment charge of $42 million for the investment in Constitution. See Note 13 for additional information.

(d) Commercial Renewables includes an impairment charge of $91 million, net of $2 million Noncontrolling interests, related to goodwill. See Note 12 for additional information.

(e) Other includes $65 million of after-tax costs to achieve the Piedmont merger, $144 million of after-tax severance charges related to a companywide initiative and an $82 million after-tax loss on the sale of Beckjord described below. For additional information, see Note 2 for the Piedmont Merger and Note 21 for severance charges.

In February 2018, Duke Energy sold Beckjord, a nonregulated facility retired during 2014, and recorded a pretax loss of $106 million within (Losses) Gains on Sales of Other Assets and Other, net and $1 million within Operation, maintenance and other on Duke Energy's Consolidated Statements of Operations for the year ended December 31, 2018. The sale included the transfer of coal ash basins and other real property and indemnification from any and all potential future claims related to the property, whether arising under environmental laws or otherwise.

	Year Ended December 31, 2017						
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total Reportable Segments	Other	Eliminations	Total
Unaffiliated Revenues	$ 21,300	$ 1,743	$ 460	$ 23,503	$ 62	$ —	$ 23,565
Intersegment Revenues	31	93	—	124	76	(200)	—
Total Revenues	$ 21,331	$ 1,836	$ 460	$ 23,627	$ 138	$ (200)	$ 23,565
Interest Expense	$ 1,240	$ 105	$ 87	$ 1,432	$ 574	$ (20)	$ 1,986
Depreciation and amortization	3,010	231	155	3,396	131	—	3,527
Equity in earnings (losses) of unconsolidated affiliates	5	62	(5)	62	57	—	119
Income tax expense (benefit)[a]	1,355	116	(628)	843	353	—	1,196
Segment income (loss)[b][c][d]	3,210	319	441	3,970	(905)	—	3,065
Add back noncontrolling interest component							5
Loss from discontinued operations, net of tax							(6)
Net income							$ 3,064
Capital investments expenditures and acquisitions	$ 7,024	$ 907	$ 92	$ 8,023	$ 175	$ —	$ 8,198
Segment assets	119,423	11,462	4,156	135,041	2,685	188	137,914

(a) All segments include impacts of the Tax Act. Electric Utilities and Infrastructure includes a $231 million benefit, Gas Utilities and Infrastructure includes a $26 million benefit, Commercial Renewables includes a $442 million benefit and Other includes charges of $597 million.

(b) Electric Utilities and Infrastructure includes after-tax regulatory settlement charges of $98 million.

(c) Commercial Renewables includes after-tax impairment charges of $74 million related to certain wind projects and the Energy Management Solutions reporting unit. See Notes 11 and 12 for additional information.

(d) Other includes $64 million of after-tax costs to achieve the Piedmont merger. See Note 2 for additional information.

Geographical Information

Substantially all assets and revenues from continuing operations are within the U.S.

Major Customers

For the year ended December 31, 2019, revenues from one customer of Duke Energy Progress are $635 million. Duke Energy Progress has one reportable segment, Electric Utilities and Infrastructure. No other Subsidiary Registrant has an individual customer representing more than 10% of its revenues.

Products and Services

The following table summarizes revenues of the reportable segments by type.

(in millions)	Retail Electric	Wholesale Electric	Retail Natural Gas	Other	Total Revenues
2019					
Electric Utilities and Infrastructure	**$ 19,745**	**$ 2,231**	**$ —**	**$ 855**	**$ 22,831**
Gas Utilities and Infrastructure	**—**	**—**	**1,782**	**84**	**1,866**
Commercial Renewables	**—**	**389**	**—**	**98**	**487**
Total Reportable Segments	**$ 19,745**	**$ 2,620**	**$ 1,782**	**$ 1,037**	**$ 25,184**
2018					
Electric Utilities and Infrastructure	$ 19,013	$ 2,345	$ —	$ 915	$ 22,273
Gas Utilities and Infrastructure	—	—	1,817	64	1,881
Commercial Renewables	—	375	—	102	477
Total Reportable Segments	$ 19,013	$ 2,720	$ 1,817	$ 1,081	$ 24,631
2017					
Electric Utilities and Infrastructure	$ 18,177	$ 2,104	$ —	$ 1,050	$ 21,331
Gas Utilities and Infrastructure	—	—	1,732	104	1,836
Commercial Renewables	—	375	—	85	460
Total Reportable Segments	$ 18,177	$ 2,479	$ 1,732	$ 1,239	$ 23,627

Duke Energy Ohio

Duke Energy Ohio has two reportable segments, Electric Utilities and Infrastructure and Gas Utilities and Infrastructure.

Electric Utilities and Infrastructure transmits and distributes electricity in portions of Ohio and generates, distributes and sells electricity in portions of Northern Kentucky. Gas Utilities and Infrastructure transports and sells natural gas in portions of Ohio and Northern Kentucky. Both reportable segments conduct operations primarily through Duke Energy Ohio and its wholly owned subsidiary, Duke Energy Kentucky.

The remainder of Duke Energy Ohio's operations is presented as Other. In December 2018, the PUCO approved an order which allows the recovery or credit of revenues and expenses related to Duke Energy Ohio's contractual arrangement to buy power from OVEC power plants. Due to the change in regulatory treatment of these amounts, OVEC revenues and expenses are now reflected in the Electric Utilities and Infrastructure segment. Previously, OVEC revenues and expense were included in Other. These amounts are deemed immaterial for Duke Energy Ohio. Therefore, no prior period amounts were restated. See Note 4 for additional information on the PUCO order.

All Duke Energy Ohio assets and revenues from continuing operations are within the U.S.

	Year Ended December 31, 2019					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	Total
Total revenues	$ 1,456	$ 484	$ 1,940	$ —	$ —	$ 1,940
Interest expense	$ 80	$ 29	$ 109	$ —	$ —	$ 109
Depreciation and amortization	182	83	265	—	—	265
Income tax expense (benefit)	20	21	41	(1)	—	40
Segment income (loss)/Net income	159	85	244	(5)	—	239
Loss from discontinued operations, net of tax						(1)
Net income						$ 238
Capital expenditures	$ 680	$ 272	$ 952	$ —	$ —	$ 952
Segment assets	6,188	3,116	9,304	34	—	9,338

	Year Ended December 31, 2018					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	Total
Total revenues	$ 1,450	$ 506	$ 1,956	$ 1	$ —	$ 1,957
Interest expense	$ 67	$ 24	$ 91	$ 1	$ —	$ 92
Depreciation and amortization	183	85	268	—	—	268
Income tax expense (benefit)	47	24	71	(28)	—	43
Segment income (loss)/Net income[a]	186	93	279	(103)	—	176
Capital expenditures	$ 655	$ 172	$ 827	$ —	$ —	$ 827
Segment assets	5,643	2,874	8,517	38	—	8,555

(a) Other includes the loss on the sale of Beckjord, see discussion above.

	Year Ended December 31, 2017					
(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Total Reportable Segments	Other	Eliminations	Total
Total revenues	$ 1,373	$ 508	$ 1,881	$ 42	$ —	$ 1,923
Interest expense	$ 62	$ 28	$ 90	$ 1	$ —	$ 91
Depreciation and amortization	178	83	261	—	—	261
Income tax expense (benefit)	40	39	79	(20)	—	59
Segment income (loss)	138	85	223	(30)	—	193
Loss from discontinued operations, net of tax						(1)
Net income						$ 192
Capital expenditures	$ 491	$ 195	$ 686	$ —	$ —	$ 686
Segment assets	5,066	2,758	7,824	66	(15)	7,875

4. REGULATORY MATTERS

REGULATORY ASSETS AND LIABILITIES

The Duke Energy Registrants record regulatory assets and liabilities that result from the ratemaking process. See Note 1 for further information.

The following tables present the regulatory assets and liabilities recorded on the Consolidated Balance Sheets of Duke Energy and Progress Energy. See separate tables below for balances by individual registrant.

	Duke Energy		Progress Energy	
	December 31,		December 31,	
(in millions)	2019	2018	2019	2018
Regulatory Assets				
AROs – coal ash	**$ 4,084**	$ 4,255	**$ 1,843**	$ 2,061
AROs – nuclear and other	**739**	772	**668**	601
Accrued pension and OPEB	**2,391**	2,654	**897**	1,074
Storm cost deferrals	**1,399**	1,117	**1,214**	953
Nuclear asset securitized balance, net	**1,042**	1,093	**1,042**	1,093
Debt fair value adjustment	**1,019**	1,099	**—**	—
Deferred fuel and purchased power	**528**	838	**305**	600
Deferred asset – Lee and Harris COLA	**388**	426	**38**	43
Hedge costs deferrals	**356**	204	**129**	74
Demand side management (DSM)/Energy Efficiency (EE)	**343**	449	**241**	256
Advanced metering infrastructure (AMI)	**338**	367	**114**	127
Retired generation facilities	**331**	402	**266**	324
Post-in-service carrying costs (PISCC) and deferred operating expenses	**329**	320	**33**	36
Vacation accrual	**214**	213	**41**	41
Derivatives – natural gas supply contracts	**117**	141	**—**	—
Nuclear deferral	**107**	133	**40**	46
Manufactured gas plant (MGP)	**102**	99	**—**	—
Deferred pipeline integrity costs	**79**	65	**—**	—
NCEMPA deferrals	**72**	50	**72**	50
East Bend deferrals	**44**	47	**—**	—
Transmission expansion obligation	**36**	39	**—**	—
Amounts due from customers	**36**	24	**—**	—
Grid modernization	**28**	31	**—**	—
Other	**896**	784	**349**	322
Total regulatory assets	**15,018**	15,622	**7,292**	7,701
Less: current portion	**1,796**	2,005	**946**	1,137
Total noncurrent regulatory assets	**$ 13,222**	$ 13,617	**$ 6,346**	$ 6,564
Regulatory Liabilities				
Net regulatory liability related to income taxes	**$ 7,872**	$ 8,058	**$ 2,595**	$ 2,710

Costs of removal	**5,756**	5,421	**2,561**	2,135
AROs – nuclear and other	**1,100**	538	**—**	—
Accrued pension and OPEB	**176**	301	**—**	149
Amounts to be refunded to customers	**34**	34	**—**	—
Deferred fuel and purchased power	**1**	16	**1**	16
Other	**1,109**	1,064	**398**	319
Total regulatory liabilities	**16,048**	15,432	**5,555**	5,329
Less: current portion	**784**	598	**330**	280
Total noncurrent regulatory liabilities	**$ 15,264**	$ 14,834	**$ 5,225**	$ 5,049

Descriptions of regulatory assets and liabilities summarized in the tables above and below follow. See tables below for recovery and amortization periods at the separate registrants.

AROs – coal ash. Represents deferred depreciation and accretion related to the legal obligation to close ash basins. The costs are deferred until recovery treatment has been determined. See Notes 1 and 10 for additional information.

AROs – nuclear and other. Represents regulatory assets or liabilities, including deferred depreciation and accretion, related to legal obligations associated with the future retirement of property, plant and equipment, excluding amounts related to coal ash. The AROs relate primarily to decommissioning nuclear power facilities. The amounts also include certain deferred gains and losses on NDTF investments. See Notes 1 and 10 for additional information.

Accrued pension and OPEB. Accrued pension and OPEB represent regulatory assets and liabilities related to each of the Duke Energy Registrants' respective shares of unrecognized actuarial gains and losses and unrecognized prior service cost and credit attributable to Duke Energy's pension plans and OPEB plans. The regulatory asset or liability is amortized with the recognition of actuarial gains and losses and prior service cost and credit to net periodic benefit costs for pension and OPEB plans. The accrued pension and OPEB regulatory assets are expected to be recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

Storm cost deferrals. Represents deferred incremental costs incurred related to major weather-related events.

Nuclear asset securitized balance, net. Represents the balance associated with Crystal River Unit 3 retirement approved for recovery by the FPSC on September 15, 2015, and the upfront financing costs securitized in 2016 with issuance of the associated bonds. The regulatory asset balance is net of the AFUDC equity portion.

Debt fair value adjustment. Purchase accounting adjustments recorded to state the carrying value of Progress Energy and Piedmont at fair value in connection with the 2012 and 2016 mergers, respectively. Amount is amortized over the life of the related debt.

Deferred fuel and purchased power. Represents certain energy-related costs that are recoverable or refundable as approved by the applicable regulatory body.

Deferred asset – Lee and Harris COLA. Represents deferred costs incurred for the canceled Lee and Harris nuclear projects.

Hedge costs and other deferrals. Amounts relate to unrealized gains and losses on derivatives recorded as a regulatory asset or liability, respectively, until the contracts are settled.

DSM/EE. Deferred costs related to various DSM and EE programs recoverable through various mechanisms.

AMI. Represents deferred costs related to the installation of AMI meters and remaining net book value of non-AMI meters to be replaced at Duke Energy Carolinas, net book value of existing meters at Duke Energy Florida, Duke Energy Progress and Duke Energy Ohio and expected future recovery of net book value of electromechanical meters that have been replaced with AMI meters at Duke Energy Indiana.

Retired generation facilities. Represents amounts to be recovered for facilities that have been retired and are probable of recovery.

Post-in-service carrying costs (PISCC) and deferred operating expenses. Represents deferred depreciation and operating expenses as well as carrying costs on the portion of capital expenditures placed in service but not yet reflected in retail rates as plant in service.

Vacation accrual. Represents vacation entitlement, which is generally recovered in the following year.

Derivatives – natural gas supply contracts. Represents costs for certain long-dated, fixed quantity forward gas supply contracts, which are recoverable through PGA clauses.

Nuclear deferral. Includes amounts related to levelizing nuclear plant outage costs, which allows for the recognition of nuclear outage expenses over the refueling cycle rather than when the outage occurs, resulting in the deferral of operations and maintenance costs associated with refueling.

MGP. Represents remediation costs incurred at former MGP sites and the deferral of costs to be incurred at Duke Energy Ohio's East End and West End sites.

Deferred pipeline integrity costs. Represents pipeline integrity management costs in compliance with federal regulations recovered through a rider mechanism.

NCEMPA deferrals. Represents retail allocated cost deferrals and returns associated with the additional ownership interest in assets acquired from NCEMPA in 2015.

East Bend deferrals. Represents both deferred operating expenses and deferred depreciation as well as carrying costs on the portion of East Bend that was acquired from Dayton Power and Light and that had been previously operated as a jointly owned facility.

Transmission expansion obligation. Represents transmission expansion obligations related to Duke Energy Ohio's withdrawal from MISO.

Amounts due from customers. Relates primarily to margin decoupling and IMR recovery mechanisms.

Grid modernization. Amounts represent deferred depreciation and operating expenses as well as carrying costs on the portion of capital expenditures placed in service but not yet reflected in retail rates as plant in service.

Net regulatory liability related to income taxes. Amounts for all registrants include regulatory liabilities related primarily to impacts from the Tax Act. See Note 24 for additional information. Amounts have no immediate impact on rate base as regulatory assets are offset by deferred tax liabilities.

Costs of removal. Represents funds received from customers to cover the future removal of property, plant and equipment from retired or abandoned sites as property is retired. Also includes certain deferred gains on NDTF investments.

Amounts to be refunded to customers. Represents required rate reductions to retail customers by the applicable regulatory body.

RESTRICTIONS ON THE ABILITY OF CERTAIN SUBSIDIARIES TO MAKE DIVIDENDS, ADVANCES AND LOANS TO DUKE ENERGY

As a condition to the approval of merger transactions, the NCUC, PSCSC, PUCO, KPSC and IURC imposed conditions on the ability of Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio, Duke Energy Kentucky, Duke Energy Indiana and Piedmont to transfer funds to Duke Energy through loans or advances, as well as restricted amounts available to pay dividends to Duke Energy. Certain subsidiaries may transfer funds to the Parent by obtaining approval of the respective state regulatory commissions. These conditions imposed restrictions on the ability of the public utility subsidiaries to pay cash dividends as discussed below.

Duke Energy Progress and Duke Energy Florida also have restrictions imposed by their first mortgage bond indentures, which in certain circumstances, limit their ability to make cash dividends or distributions on common stock. Amounts restricted as a result of these provisions were not material at December 31, 2019.

Additionally, certain other subsidiaries of Duke Energy have restrictions on their ability to dividend, loan or advance funds to Duke Energy due to specific legal or regulatory restrictions, including, but not limited to, minimum working capital and tangible net worth requirements.

The restrictions discussed below were not a material amount of Duke Energy's and Progress Energy's net assets at December 31, 2019.

Duke Energy Carolinas

Duke Energy Carolinas must limit cumulative distributions subsequent to mergers to (i) the amount of retained earnings on the day prior to the closing of the mergers, plus (ii) any future earnings recorded.

Duke Energy Progress

Duke Energy Progress must limit cumulative distributions subsequent to the mergers between Duke Energy and Progress Energy and Duke Energy and Piedmont to (i) the amount of retained earnings on the day prior to the closing of the respective mergers, plus (ii) any future earnings recorded.

Duke Energy Ohio

Duke Energy Ohio will not declare and pay dividends out of capital or unearned surplus without the prior authorization of the PUCO. Duke Energy Ohio received FERC and PUCO approval to pay dividends from its equity accounts that are reflective of the amount that it would have in its retained earnings account had push-down accounting for the Cinergy merger not been applied to Duke Energy Ohio's balance sheet. The conditions include a commitment from Duke Energy Ohio that equity, adjusted to remove the impacts of push-down accounting, will not fall below 30% of total capital.

Duke Energy Kentucky is required to pay dividends solely out of retained earnings and to maintain a minimum of 35% equity in its capital structure.

Duke Energy Indiana

Duke Energy Indiana must limit cumulative distributions subsequent to the merger between Duke Energy and Cinergy to (i) the amount of retained earnings on the day prior to the closing of the merger, plus (ii) any future earnings recorded. In addition, Duke Energy Indiana will not declare and pay dividends out of capital or unearned surplus without prior authorization of the IURC.

Piedmont

Piedmont must limit cumulative distributions subsequent to the acquisition of Piedmont by Duke Energy to (i) the amount of retained earnings on the day prior to the closing of the merger, plus (ii) any future earnings recorded.

RATE-RELATED INFORMATION

The NCUC, PSCSC, FPSC, IURC, PUCO, TPUC and KPSC approve rates for retail electric and natural gas services within their states. The FERC approves rates for electric sales to wholesale customers served under cost-based rates (excluding Ohio and Indiana), as well as sales of transmission service. The FERC also regulates certification and siting of new interstate natural gas pipeline projects.

Duke Energy Carolinas and Duke Energy Progress

Hurricane Florence, Hurricane Michael and Winter Storm Diego Deferral Filings

On December 21, 2018, Duke Energy Carolinas and Duke Energy Progress filed with the NCUC petitions for approval to defer the incremental costs incurred in connection with the response to Hurricane Florence, Hurricane Michael and Winter Storm Diego to a regulatory asset for recovery in the next base rate case. The NCUC issued an order requesting comments on the deferral positions. On March 5, 2019, the North Carolina Public Staff (Public Staff) filed comments. On April 2, 2019, Duke Energy Carolinas and Duke Energy Progress filed reply comments, which included revised estimates of approximately $553 million in incremental operation and maintenance expenses ($171 million and $382 million for Duke Energy Carolinas and Duke Energy Progress, respectively) and approximately $96 million in capital costs ($20 million and $76 million for Duke Energy Carolinas and Duke Energy Progress, respectively). On September 30, 2019, Duke Energy Carolinas requested that the NCUC consolidate its pending deferral request with its general rate case filed on that date. On October 30, 2019, Duke Energy Progress requested that the NCUC consolidate its pending deferral request with its general rate case filed on that date. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of these matters. Duke Energy Progress filed a deferral request for these storms with the PSCSC on January 11, 2019, which also included a request for the continuation of prior deferrals requested for ice storms and Hurricane Matthew, and on January 30, 2019, the PSCSC issued a directive approving the deferral request, followed by an order issued on February 21, 2019. On March 15, 2019, Duke Energy Progress filed a request with FERC requesting permission to defer transmission-related storm costs that would be charged to wholesale transmission customers through Duke Energy Progress' Open Access Transmission Tariff (OATT) and to recover those costs from wholesale transmission customers over a three-year recovery period. FERC accepted the filing on May 14, 2019, which allows Duke Energy Progress to proceed with the proposed cost deferral and recovery.

Duke Energy Carolinas

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Carolinas' Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	**$ 1,696**	$ 1,725	(i)	(b)
Accrued pension and OPEB	**477**	581		(j)
Storm cost deferrals	**178**	160	Yes	(b)
Deferred fuel and purchased power	**222**	196	(f)	2021
Deferred asset – Lee COLA	**350**	383		(b)
Hedge costs deferrals[c]	**198**	101	Yes	2041
DSM/EE	**100**	169	(h)	(h)
AMI	**166**	176	Yes	(b)
Retired generation facilities[c]	**16**	21	Yes	2023
PISCC[c]	**33**	34	Yes	(b)
Vacation accrual	**80**	78	(e)	2020
Nuclear deferral	**67**	87		2021
Other	**327**	266		(b)
Total regulatory assets	**3,910**	3,977		
Less: current portion	**550**	520		
Total noncurrent regulatory assets	**$ 3,360**	$ 3,457		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[d]	**$ 3,060**	$ 3,082		(b)
Costs of removal[c]	**1,936**	1,968	Yes	(g)
AROs – nuclear and other	**1,100**	538		(b)
Accrued pension and OPEB	**39**	38		(j)
Other	**543**	572		(b)
Total regulatory liabilities	**6,678**	6,198		
Less: current portion	**255**	199		
Total noncurrent regulatory liabilities	**$ 6,423**	$ 5,999		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Includes regulatory liabilities related to the change in the federal tax rate as a result of the Tax Act and the change in the North Carolina tax rate, both discussed in Note 24.
(e) Earns a return on outstanding balance in North Carolina.
(f) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.
(g) Recovered over the life of the associated assets.

(h) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.

(i) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.

(j) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

2017 North Carolina Rate Case

On August 25, 2017, Duke Energy Carolinas filed an application with the NCUC for a rate increase for retail customers of approximately $647 million, which represented an approximate 13.6% increase in annual base revenues. The request for rate increase was driven by capital investments subsequent to the previous base rate case, including the W.S. Lee CC, grid improvement projects, AMI, investments in customer service technologies, costs of complying with CCR regulations and the Coal Ash Act and recovery of costs related to licensing and development of the William States Lee III Nuclear Station.

On February 28, 2018, Duke Energy Carolinas and the Public Staff filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding. Terms of the settlement included a return on equity of 9.9% and a capital structure of 52% equity and 48% debt. As a result of the settlement, Duke Energy Carolinas recorded a pretax charge of approximately $4 million in the first quarter of 2018 to Operation, maintenance and other on the Consolidated Statements of Operations.

On June 22, 2018, the NCUC issued an order approving the Stipulation of Partial Settlement and requiring a revenue reduction.

As a result of the June 22, 2018, order, Duke Energy Carolinas recorded a pretax charge of approximately $150 million to Impairment charges and Operation, maintenance and other on the Consolidated Statements of Operations. The charge was primarily related to the denial of a return on the Lee Nuclear Project and the assessment of a $70 million management penalty by reducing the annual recovery of deferred coal ash costs by $14 million per year over a five-year recovery period. On July 27, 2018, NCUC approved Duke Energy Carolinas' compliance filing. As a result, revised customer rates were effective on August 1, 2018.

On July 20, 2018, the North Carolina Attorney General filed a Notice of Appeal to the North Carolina Supreme Court from the June 22, 2018, Order Accepting Stipulation, Deciding Contested Issues and Requiring Revenue Reduction issued by the NCUC. The Attorney General contends the commission's order should be reversed and remanded, as it is in excess of the commission's statutory authority; affected by errors of law; unsupported by competent, material and substantial evidence in view of the entire record as submitted; and arbitrary or capricious. The Sierra Club, North Carolina Sustainable Energy Association, North Carolina Justice Center, North Carolina Housing Coalition, Natural Resource Defense Council and Southern Alliance for Clean Energy also filed Notices of Appeal to the North Carolina Supreme Court. On August 8, 2018, the Public Staff filed a Notice of Cross Appeal to the North Carolina Supreme Court, which contends the commission's June 22, 2018, order should be reversed and remanded, as it is affected by errors of law, and is unsupported by substantial evidence with regard to the commission's failure to consider substantial evidence of coal ash related environmental violations. On November 29, 2018, the North Carolina Attorney General's Office filed a motion with the North Carolina Supreme Court requesting the court consolidate the Duke Energy Carolinas and Duke Energy Progress appeals and enter an order adopting the parties' proposed briefing schedule as set out in the filing. On November 29, 2018, the North Carolina Supreme Court adopted a schedule for briefing set forth in the motion to consolidate the Duke Energy Carolinas and Duke Energy Progress appeals. Appellant briefs were filed on April 26, 2019. The Appellee response briefs were filed on September 25, 2019. Oral arguments before the North Carolina Supreme Court are scheduled for March 11, 2020. Duke Energy Carolinas cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On September 30, 2019, Duke Energy Carolinas filed an application with the NCUC for a net rate increase for retail customers of approximately $291 million, which represents an approximate 6% increase in annual base revenues. The gross rate case revenue increase request is $445 million, which is offset by an EDIT rider of $154 million to return to customers North Carolina and federal EDIT resulting from recent reductions in corporate tax rates. The request for rate increase is driven by major capital investments subsequent to the previous base rate case, coal ash pond closure costs, accelerated coal plant depreciation and deferred 2018 storm costs. Duke Energy Carolinas requests rates be effective no later than August 1, 2020. The NCUC has established a procedural schedule with an evidentiary hearing to commence on March 23, 2020. Duke Energy Carolinas cannot predict the outcome of this matter.

2018 South Carolina Rate Case

On November 8, 2018, Duke Energy Carolinas filed an application with the PSCSC for a rate increase for retail customers of approximately $168 million, which represents an approximate 10% increase in retail revenues. The request for rate increase was driven by capital investments and environmental compliance progress made by Duke Energy Carolinas since its previous rate case, including the further implementation of Duke Energy Carolinas' generation modernization program, which consists of retiring, replacing and upgrading generation plants, investments in customer service technologies and continued investments in base work to maintain its transmission and distribution systems. The request included net tax benefits resulting from the Tax Act of $66 million to reflect the change in ongoing tax expense, primarily from the reduction in the federal income tax rate from 35% to 21%. The request also included $46 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change and benefits of $17 million from a reduction in North Carolina state income taxes allocable to South Carolina (EDIT Rider).

Duke Energy Carolinas also requested approval of its proposed Grid Improvement Plan (GIP), adjustments to its Prepaid Advantage Program and a variety of accounting orders related to ongoing costs for environmental compliance, including recovery over a five-year period of $242 million of deferred coal ash related compliance costs, grid investments between rate changes, incremental depreciation expense, a result of new depreciation rates from the depreciation study approved in the 2017 North Carolina Rate Case above, and the balance of development costs associated with the cancellation of the Lee Nuclear Project. Finally, Duke Energy Carolinas sought approval to establish a reserve and accrual for end-of-life nuclear costs for nuclear fuel and materials and supplies. On March 8, 2019, the ORS moved to establish a new and separate hearing docket to review and consider the GIP proposed by Duke Energy Carolinas. Subsequently, on March 12, 2019, the ORS and Duke Energy Carolinas executed a Stipulation resolving the ORS's motion. The Stipulation provided that costs incurred for the GIP after January 1, 2019, would be deferred with a return, subject to evaluation in a future rate proceeding. The Stipulation was approved by the PSCSC on June 19, 2019. On December 16, 2019, Duke Energy Carolinas and Duke Energy Progress filed a Joint Petition to Establish an Informational Docket for Review and Consideration of Grid Improvement Plans through which Duke Energy Carolinas and Duke Energy Progress would provide interested stakeholders information on the companies' grid activities. The PSCSC requested parties comment on procedural matters by January 31; accordingly, various groups filed comments, none of which opposed an informational docket. Duke Energy Carolinas cannot predict the outcome of this matter.

After hearings in March 2019, the PSCSC issued an order on May 21, 2019, which included a return on equity of 9.5% and a capital structure of 53% equity and 47% debt. The order also included the following material components:

- Approval of cancellation of the Lee Nuclear Project, with Duke Energy Carolinas maintaining the Combined Operating License;
- Approval of recovery of $125 million (South Carolina retail portion) of Lee Nuclear Project development costs (including AFUDC through December 2017) over a 12-year period, but denial of a return on the deferred balance of costs;
- Approval of recovery of $96 million of coal ash costs over a five-year period with a return at Duke Energy Carolinas' WACC;
- Denial of recovery of $115 million of certain coal ash costs deemed to be related to the Coal Ash Act and incremental to the federal CCR rule;
- Approval of a $66 million decrease to base rates to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35% to 21%;
- Approval of a $45 million decrease through the EDIT Rider to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change, to be returned in accordance with the Average Rate Assumption Method (ARAM) for protected EDIT, over a 20-year period for unprotected EDIT associated with Property, Plant and Equipment, over a five-year period for unprotected EDIT not associated with Property, Plant and Equipment and over a five-year period for the deferred revenues; and
- Approval of a $17 million decrease through the EDIT Rider related to reductions in the North Carolina state income tax rate from 6.9% to 2.5% to be returned over a five-year period.

As a result of the order, revised customer rates were effective June 1, 2019. On May 31, 2019, Duke Energy Carolinas filed a Petition for Rehearing or Reconsideration of that order contending substantial rights of Duke Energy Carolinas were prejudiced by unlawful, arbitrary and capricious rulings by the commission on certain issues presented in the proceeding. On June 19, 2019, the PSCSC issued a Directive denying Duke Energy Carolinas' request to rehear or reconsider the commission's rulings on certain issues presented in the proceeding including coal ash remediation and disposal costs, return on equity and the recovery of a return on deferred operation and maintenance expenses. An order detailing the commission's decision in the Directive was issued on October 18, 2019. Duke Energy Carolinas filed a notice of appeal on November 15, 2019, with the South Carolina Supreme Court. On November 20, 2019, the South Carolina Energy Users Committee filed a Notice of Appeal and the ORS filed a Notice of Cross Appeal with the South Carolina Supreme Court. On January 8, 2020, Duke Energy Carolinas and the ORS filed a joint motion to extend briefing schedule deadlines. Appellant briefs are due on March 2, 2020, and Appellee response briefs are due on May 15, 2020. On February 12, 2020, Duke Energy Carolinas and the ORS filed a joint motion to extend briefing deadlines by 30 days. Based on legal analysis and the filing of the appeal, Duke Energy Carolinas has not recorded an adjustment for its deferred coal ash costs. Duke Energy Carolinas cannot predict the outcome of this matter.

FERC Formula Rate Matter

On July 31, 2017, PMPA filed a complaint with FERC alleging that Duke Energy Carolinas misapplied the formula rate under the PPA between the parties by including in its rates amortization expense associated with regulatory assets and recorded in a certain account without FERC approval. On February 15, 2018, FERC issued an order ruling in favor of PMPA and ordered Duke Energy Carolinas to refund to PMPA all amounts improperly collected under the PPA. Duke Energy Carolinas has issued to PMPA and similarly situated wholesale customers refunds of approximately $25 million. FERC also set the matter for settlement and hearing. PMPA and other customers filed a protest to Duke Energy Carolinas' refund report claiming that the refunds are inadequate in that (1) Duke Energy Carolinas invoked the limitations periods in the contracts to limit the time period for which the refunds were paid and the customers disagree that this limitation applies, and (2) Duke Energy Carolinas refunded only amounts recovered through a certain account and the customers have asserted that the order applies to all regulatory assets. On July 3, 2018, FERC issued an order accepting Duke Energy Carolinas' refund report and ruling that these two claims are outside the scope of FERC's February order. The settlement agreements and revised formula rates for all parties to the proceeding were filed on December 28, 2018. On April 2, 2019, FERC issued an order approving the settlement agreement as filed. Since then, Duke Energy Carolinas has implemented the terms of the settlement in rates with all wholesale customers, including non-intervening customers. On July 25, 2019, Duke Energy Carolinas received FERC approval for the accounting treatment requested for certain assets included in the settlement agreements. This is the final approval needed from FERC and concludes this proceeding.

Sale of Hydroelectric (Hydro) Plants

In May 2018, Duke Energy Carolinas entered an agreement for the sale of five hydro plants with a combined 18.7-MW generation capacity in the Western Carolinas region to Northbrook Energy. The completion of the transaction was subject to approval from FERC for the four FERC-licensed plants, as well as other state regulatory agencies and was contingent upon regulatory approval from the NCUC and PSCSC to defer the total estimated loss on the sale of approximately $40 million. On July 5, 2018, Duke Energy Carolinas filed with the NCUC for approval of the sale of the five hydro plants to Northbrook, to transfer the CPCNs for the four North Carolina hydro plants and to establish a regulatory asset for the North Carolina retail portion of the difference between sales proceeds and net book value. On June 5, 2019, the NCUC issued an order approving the transfer of the hydro plants from Duke Energy Carolinas to Northbrook, granting deferral accounting and denying the Public Staff's motion for reconsideration.

On August 28, 2018, Duke Energy Carolinas filed with PSCSC an Application for Approval of Transfer and Sale of Hydroelectric Generation Facilities, Acceptance for Filing of a Power Purchase Agreement and an Accounting Order to Establish a Regulatory Asset. On September 10, 2018, the ORS provided a letter to the commission stating its position on the application and on September 18, 2018, Duke Energy Carolinas requested this matter be carried over to allow Duke Energy Carolinas time to discuss certain accounting issues with the ORS. At its June 26, 2019, agenda meeting, the PSCSC voted to approve the transfer and sale subject to the recommendation of the ORS that the issuance of an Accounting Order will not preclude the ORS, the commission or any other party from addressing the reasonableness of these costs, any return sought and including any carrying costs in the next rate case.

On August 9, 2018, Duke Energy Carolinas and Northbrook filed a joint Application for Transfer of Licenses with the FERC. On December 27, 2018, the FERC issued its Order Approving Transfer of Licenses for the four FERC-licensed hydro plants. On January 18, 2019, Duke Energy Carolinas and Northbrook Carolina Hydro II, LLC requested a six-month extension of time to comply with the requirement of the December 27, 2018, order that Northbrook submit to FERC certified copies of all instruments of conveyance and signed acceptance sheets within 60 days of the date of the order. On February 14, 2019, FERC issued an order granting extensions until August 26, 2019, to comply with the requirements of the December 27, 2018, order.

The closing occurred on August 16, 2019. A regulatory asset was established for approximately $32 million, which represents the total deferral amount for North Carolina and South Carolina retail. The North Carolina retail portion will be amortized pursuant to an order from the NCUC. Duke Energy Carolinas will purchase all the capacity and energy generated by these facilities at the avoided cost for five years through power purchase agreements.

Duke Energy Progress

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Progress' Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	$ **1,834**	$ 2,051	(h)	(b)
AROs – nuclear and other	**509**	429		(c)
Accrued pension and OPEB	**423**	542		(k)
Storm cost deferrals[d]	**801**	571	Yes	(b)
Deferred fuel and purchased power	**266**	397	(f)	2021
Deferred asset – Harris COLA	**38**	43		
Hedge costs deferrals	**85**	54		(b)
DSM/EE[e]	**216**	235	(i)	(i)
AMI	**61**	67		(b)
Retired generation facilities	**83**	105	Yes	(b)
PISCC and deferred operating expenses	**33**	36	Yes	2054
Vacation accrual	**41**	41		2020
Nuclear deferral	**40**	46		2021
NCEMPA deferrals	**72**	50	(g)	2042
Other	**176**	147		(b)
Total regulatory assets	**4,678**	4,814		
Less: current portion	**526**	703		
Total noncurrent regulatory assets	$ **4,152**	$ 4,111		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[l]	$ **1,802**	$ 1,863		(b)
Costs of removal	**2,294**	1,878	Yes	(j)
Accrued pension and OPEB	**—**	93		(k)
Other	**372**	299		(b)
Total regulatory liabilities	**4,468**	4,133		
Less: current portion	**236**	178		
Total noncurrent regulatory liabilities	$ **4,232**	$ 3,955		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Recovery period for costs related to nuclear facilities runs through the decommissioning period of each unit.
(d) South Carolina storm costs are included in rate base.
(e) Included in rate base.
(f) Pays interest on over-recovered costs in North Carolina. Includes certain purchased power costs in North Carolina and South Carolina and costs of distributed energy in South Carolina.

(g) South Carolina retail allocated costs are earning a return.
(h) Earns a debt and equity return on coal ash expenditures for North Carolina and South Carolina retail customers as permitted by various regulatory orders.
(i) Includes incentives on DSM/EE investments and is recovered through an annual rider mechanism.
(j) Recovered over the life of the associated assets.
(k) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.
(l) Includes regulatory liabilities related to the change in the federal tax rate as a result of the Tax Act and the change in the North Carolina tax rate, both discussed in Note 23.

2017 North Carolina Rate Case

On June 1, 2017, Duke Energy Progress filed an application with the NCUC for a rate increase for retail customers of approximately $477 million, which represented an approximate 14.9% increase in annual base revenues. Subsequent to the filing, Duke Energy Progress adjusted the requested amount to $420 million, representing an approximate 13% increase. The request for rate increase was driven by capital investments subsequent to the previous base rate case, costs of complying with CCR regulations and the Coal Ash Act, costs relating to storm recovery, investments in customer service technologies and recovery of costs associated with renewable purchased power.

On November 22, 2017, Duke Energy Progress and the Public Staff filed an Agreement and Stipulation of Partial Settlement resolving certain portions of the proceeding. Terms of the settlement included a return on equity of 9.9% and a capital structure of 52% equity and 48% debt. On February 23, 2018, the NCUC issued an order approving the stipulation.

The order also impacted certain amounts that were similarly recorded on Duke Energy Carolinas' Consolidated Balance Sheets. As a result of the order, Duke Energy Progress and Duke Energy Carolinas recorded pretax charges of $68 million and $14 million, respectively, in the first quarter of 2018 to Impairment charges, Operation, maintenance and other and Interest Expense on the Consolidated Statements of Operations. Revised customer rates became effective on March 16, 2018.

On May 15, 2018, the Public Staff filed a Notice of Cross Appeal to the North Carolina Supreme Court from the NCUC's February 23, 2018, order. The Public Staff contends the NCUC's order should be reversed and remanded, as it is affected by errors of law, and is unsupported by competent, material and substantial evidence in view of the entire record as submitted. The North Carolina Attorney General and Sierra Club also filed Notices of Appeal to the North Carolina Supreme Court from the February 23, 2018, order. On November 29, 2018, the North Carolina Attorney General's Office filed a motion with the North Carolina Supreme Court requesting the court consolidate the Duke Energy Progress and Duke Energy Carolinas appeals and enter an order adopting the parties' proposed briefing schedule as set out in the filing. Appellant briefs were filed on April 26, 2019. The Appellee response briefs were filed on September 25, 2019. Oral arguments before the North Carolina Supreme Court are scheduled for March 11, 2020. Duke Energy Progress cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On October 30, 2019, Duke Energy Progress filed an application with the NCUC for a net rate increase for retail customers of approximately $464 million, which represents an approximate 12.3% increase in annual base revenues. The gross rate case revenue increase request is $586 million, which is offset by riders of $122 million, primarily an EDIT rider of $120 million to return to customers North Carolina and federal EDIT resulting from recent reductions in corporate tax rates. The request for rate increase is driven by major capital investments subsequent to the previous base rate case, coal ash pond closure costs, accelerated coal plant depreciation and deferred 2018 storm costs. Duke Energy Progress seeks to defer and recover incremental Hurricane Dorian storm costs in this proceeding and requests rates be effective no later than September 1, 2020. The NCUC has established a procedural schedule with an evidentiary hearing to commence on May 4, 2020. Duke Energy Progress cannot predict the outcome of this matter.

Hurricane Dorian

Hurricane Dorian reached the Carolinas in September 2019 as a Category 2 hurricane making landfall within Duke Energy Progress' service territory. Approximately 270,000 North Carolina customers and 30,000 South Carolina customers were impacted by the slow-moving storm that brought high winds, tornadoes and heavy rain. With storm-response mobilization occurring in preparation for the storm and the assistance of mutual aid partners, full restoration was accomplished within four days for all customers able to receive service. Total estimated incremental operation and maintenance expenses incurred to repair and restore the system are approximately $205 million with an additional $4 million in capital investments made for restoration efforts. Approximately $179 million of the operation and maintenance expenses are deferred in Regulatory assets within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019. The balance of operation and maintenance expenses are included in Operation, maintenance and other on the Consolidated Statements of Operations for the year ended December 31, 2019. A request for an accounting order to defer incremental storm costs associated with Hurricane Dorian was included in Duke Energy Progress' October 30, 2019, general rate case filing with the NCUC. Duke Energy Progress cannot predict the outcome of this matter.

2018 South Carolina Rate Case

On November 8, 2018, Duke Energy Progress filed an application with the PSCSC for a rate increase for retail customers of approximately $59 million, which represents an approximate 10.3% increase in annual base revenues. The request for rate increase was driven by capital investments and environmental compliance progress made by Duke Energy Progress since its previous rate case, including the further implementation of Duke Energy Progress' generation modernization program, which consists of retiring, replacing and upgrading generation plants, investments in customer service technologies and continued investments in base work to maintain its transmission and distribution systems. The request included a decrease resulting from the Tax Act of $17 million to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35% to 21%. The request also included $10 million to return EDIT resulting from the federal tax rate change and deferred revenues since January 2018 related to the change (EDIT Rider) and a $12 million increase due to the expiration of EDITs related to reductions in North Carolina state income taxes allocable to South Carolina.

Duke Energy Progress also requested approval of its proposed GIP, approval of a Prepaid Advantage Program and a variety of accounting orders related to ongoing costs for environmental compliance, including recovery over a five-year period of $51 million of deferred coal ash related compliance costs, AMI deployment, grid investments between rate changes and regulatory asset treatment related to the retirement of a generating plant located in Asheville, North Carolina. Finally, Duke Energy Progress sought approval to establish a reserve and accrual for end-of-life nuclear costs for materials and supplies and nuclear fuel. On March 8, 2019, the ORS moved to establish a new and separate hearing docket to review and consider the GIP proposed by Duke Energy Progress. Subsequently, on March 12, 2019, the ORS and Duke Energy Carolinas executed a Stipulation resolving the ORS's motion, and Duke Energy Progress agreed to the Stipulation, as did other parties in the rate case. The Stipulation provides that costs incurred for the GIP after January 1, 2019, would be deferred with a return, with all costs subject to evaluation in a future rate proceeding. The Stipulation was approved by the PSCSC on June 19, 2019. On December 16, 2019, Duke Energy Progress and Duke Energy Carolinas filed a Joint Petition to Establish an Informational Docket for Review and Consideration of Grid Improvement Plans through which Duke Energy Progress and Duke Energy Carolinas would provide interested stakeholders information on the companies' grid activities. The PSCSC requested parties comment on procedural matters by January 31; accordingly, various groups filed comments, none of which opposed an informational docket. Duke Energy Progress cannot predict the outcome of this matter.

After hearings in April 2019, the PSCSC issued an order on May 21, 2019, which included a return on equity of 9.5% and a capital structure of 53% equity and 47% debt. The order also included the following material components:

- Approval of recovery of $4 million of coal ash costs over a five-year period with a return at Duke Energy Progress' WACC;
- Denial of recovery of $65 million of certain coal ash costs deemed to be related to the Coal Ash Act and incremental to the federal CCR rule;
- Approval of a $17 million decrease to base rates to reflect the change in ongoing tax expense, primarily the reduction in the federal income tax rate from 35% to 21%;
- Approval of a $12 million decrease through the EDIT Tax Savings Rider resulting from the federal tax rate change and deferred revenues since January 2018 related to the change, to be returned in accordance with ARAM for protected EDIT, over a 20-year period for unprotected EDIT associated with Property, Plant and Equipment, over a five-year period for unprotected EDIT not associated with Property, Plant and Equipment and over a three-year period for the deferred revenues; and
- Approval of a $12 million increase due to the expiration of EDIT related to reductions in the North Carolina state income tax rate from 6.9% to 2.5%.

As a result of the order, revised customer rates were effective June 1, 2019. On May 31, 2019, Duke Energy Progress filed a Petition for Rehearing or Reconsideration of that order contending substantial rights of Duke Energy Progress were prejudiced by unlawful, arbitrary and capricious rulings by the commission on certain issues presented in the proceeding. On June 19, 2019, the PSCSC issued a Directive denying Duke Energy Progress' request to rehear or reconsider the commission's rulings on certain issues presented in the proceeding including coal ash remediation and disposal costs, return on equity and the recovery of a return on deferred operation and maintenance expenses, but allowing additional litigation-related costs. As a result of the Directive allowing litigation-related costs, customer rates were revised effective July 1, 2019. An order detailing the commission's decision in the Directive was issued on October 18, 2019. Duke Energy Progress filed a notice of appeal on November 15, 2019, with the South Carolina Supreme Court. The ORS filed a Notice of Cross Appeal on November 20, 2019. On January 8, 2020, Duke Energy Progress and the ORS filed a joint motion to extend briefing schedule deadlines. Appellant briefs are due on March 2, 2020, and Appellee response briefs are on May 15, 2020. On February 12, 2020, Duke Energy Progress and the ORS filed a joint motion to extend briefing deadlines by 30 days. Based on legal analysis and the filing of the appeal, Duke Energy Progress has not recorded an adjustment for its deferred coal ash costs. Duke Energy Progress cannot predict the outcome of this matter.

Western Carolinas Modernization Plan

On November 4, 2015, Duke Energy Progress announced a Western Carolinas Modernization Plan, which included retirement of the existing Asheville coal-fired plant, the construction of two 280 MW combined-cycle natural gas plants having dual-fuel capability, with the option to build a third natural gas simple cycle unit in 2023 based upon the outcome of initiatives to reduce the region's power demand. The plan also included upgrades to existing transmission lines and substations, installation of solar generation and a pilot battery storage project. Duke Energy Progress worked with the local natural gas distribution company to upgrade and lease an existing natural gas pipeline to serve the natural gas plant. The lease for the new pipeline became effective on March 2, 2019.

On March 28, 2016, the NCUC issued an order approving a CPCN for the new combined-cycle natural gas plants, but is requiring Duke Energy Progress to refile for CPCN approval for the contingent simple cycle unit. On March 28, 2019, Duke Energy Progress filed an annual progress report for the construction of the combined-cycle plants with the NCUC, with an estimated cost of $893 million.

On December 27, 2019, Asheville Combined Cycle Power Block 1 and the common systems that serve both combined cycle units went into commercial operation. Power Block 1 consists of the Unit 5 Combustion Turbine and Unit 6 Steam Turbine Generator (which together form the first combined cycle unit approved in the CPCN Order). Power Block 2 consists of the Unit 7 Combustion Turbine and Unit 8 Steam Turbine Generator (which together form the second combined cycle unit approved in the CPCN Order). Duke Energy Progress placed the Unit 7 Combustion Turbine portion of Power Block 2 into commercial operation in simple-cycle mode on January 15, 2020. Duke Energy Progress currently expects to place the Unit 8 Steam Turbine Generator into commercial operation in the first quarter of 2020, after final testing has been completed.

On October 8, 2018, Duke Energy Progress filed an application with the NCUC for a CPCN to construct the Hot Springs Microgrid Solar and Battery Storage Facility. On March 22, 2019, Duke Energy Progress and the Public Staff filed a Joint Proposed Order. On May 10, 2019, the NCUC issued an Order Granting Certificate of Public Convenience and Necessity with Conditions. On November 19, 2019, Duke Energy Progress filed a semiannual progress report for its Hot Springs Microgrid Solar and Battery Storage Facility. As required by an NCUC order issued December 6, 2019, an updated progress report was filed on January 15, 2020. Construction is expected to begin in March 2020 with commercial operation expected to begin in September 2020.

The carrying value of the 376-MW Asheville coal-fired plant, including associated ash basin closure costs, of $214 million and $327 million is included in Generation facilities to be retired, net on Duke Energy Progress' Consolidated Balance Sheets as of December 31, 2019, and 2018, respectively. Duke Energy Progress' request for a regulatory asset at the time of retirement with amortization over a 10-year period was approved by the NCUC on February 23, 2018. Duke Energy Progress retired the Asheville coal-fired plant on January 29, 2020.

FERC Return on Equity Complaint

On October 11, 2019, NCEMPA filed a complaint at FERC against Duke Energy Progress pursuant to Section 206 of the Federal Power Act (FPA). The complaint alleges that the return on equity component in the formula rate contained within the Full Requirements Power Purchase Agreement (FRPPA) is unjust and unreasonable. The FRPPA's return on equity is 11% as applied to the Production Capacity Rate for the full requirements service provided by Duke Energy Progress. The complaint does not definitively propose a replacement return on equity. Under FPA Section 206, the earliest refund effective date that FERC can establish is the date of the filing of the complaint. The complaint could raise risks across the Duke Energy Progress wholesale business because, depending on how FERC treats NCEMPA's complaint, other parties may come forward with similar complaints. Duke Energy Progress cannot predict the outcome of this matter.

Duke Energy Florida

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Florida's Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash[c]	$ 9	$ 10		(b)
AROs – nuclear and other[c]	159	172		(b)
Accrued pension and OPEB[c]	474	532	Yes	(g)
Storm cost deferrals[c]	413	382	(e)	2021
Nuclear asset securitized balance, net	1,042	1,093		2036
Deferred fuel and purchased power	39	203	(f)	2021
Hedge costs deferrals	44	20		2038
DSM/EE[c]	25	21	Yes	2024
AMI[c]	53	60	Yes	2032
Retired generation facilities[c]	183	219	Yes	(b)
Other	172	176	(d)	(b)
Total regulatory assets	2,613	2,888		
Less: current portion	419	434		
Total noncurrent regulatory assets	$ 2,194	$ 2,454		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes[c]	$ 793	$ 847		(b)
Costs of removal[c]	267	257	(d)	(b)
Accrued pension and OPEB	—	56	Yes	(g)
Deferred fuel and purchased power[c]	1	16	(f)	2021
Other	26	20	(d)	(b)
Total regulatory liabilities	1,087	1,196		
Less: current portion	94	102		
Total noncurrent regulatory liabilities	$ 993	$ 1,094		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Certain costs earn/pay a return.
(e) Earns a debt return/interest once collections begin.
(f) Earns commercial paper rate.
(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

Storm Restoration Cost Recovery

In September 2017, Duke Energy Florida's service territory suffered significant damage from Hurricane Irma, resulting in approximately 1 million customers experiencing outages. In the fourth quarter of 2017, Duke Energy Florida also incurred preparation costs related to Hurricane Nate. On December 28, 2017, Duke Energy Florida filed a petition with the FPSC to recover incremental storm restoration costs for Hurricane Irma and Hurricane Nate and to replenish the storm reserve. On February 6, 2018, the FPSC approved a stipulation that would apply tax savings resulting from the Tax Act toward storm costs effective January 2018 in lieu of implementing a storm surcharge. On May 31, 2018, Duke Energy Florida filed a petition for approval of actual storm restoration costs and associated recovery process related to Hurricane Irma and Hurricane Nate. The petition sought the approval for the recovery in the amount of $510 million in actual recoverable storm restoration costs, including the replenishment of Duke Energy Florida's storm reserve of $132 million, and the process for recovering these recoverable storm costs. On August 20, 2018, the FPSC approved Duke Energy Florida's unopposed Motion for Continuance filed August 17, 2018, to allow for an evidentiary hearing in this matter. On January 28, 2019, Duke Energy Florida made a supplemental filing to reduce the total storm cost recovery from $510 million to $508 million. On April 3, 2019, the FPSC issued an Order abating all remaining filing dates. On April 9, 2019, Duke Energy Florida filed an unopposed motion to approve a settlement agreement resolving all outstanding issues in this docket. On June 13, 2019, the FPSC issued its order approving the settlement agreement. The Storm Cost Settlement Agreement obligates Duke Energy Florida to capitalize $18 million of storm costs and remove $6 million of operating and maintenance expense, thereby reducing the requested storm cost recovery amount by $24 million. Duke Energy Florida will also implement process changes with respect to storm cost restoration. At December 31, 2019, and December 31, 2018, Duke Energy Florida's Consolidated Balance Sheets included approximately $43 million and $217 million, respectively, of recoverable costs under the FPSC's storm rule in Regulatory assets within Current Assets and Other Noncurrent Assets related to storm recovery for Hurricane Irma and Hurricane Nate.

In October 2018, Duke Energy Florida's service territory suffered damage when Hurricane Michael made landfall as a Category 5 hurricane with maximum sustained winds of 160 mph. The storm caused catastrophic damage from wind and storm surge, particularly from Panama City Beach to Mexico Beach, resulting in widespread outages and significant damage to transmission and distribution facilities across the central Florida Panhandle. In response to Hurricane Michael, Duke Energy Florida restored service to approximately 72,000 customers. Total estimated incremental operation and maintenance and capital costs are $311 million. Approximately $107 million and $35 million of the costs are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019, and December 31, 2018, respectively. Approximately $204 million and $165 million of costs are included in Regulatory assets within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019, and December 31, 2018, respectively, representing recoverable costs under the FPSC's storm rule and Duke Energy Florida's OATT formula rates.

Duke Energy Florida filed a petition with the FPSC on April 30, 2019, to recover the retail portion of incremental storm restoration costs for Hurricane Michael. On June 11, 2019, the FPSC approved the petition for recovery of incremental storm restoration costs related to Hurricane Michael. The FPSC also approved the stipulation Duke Energy Florida filed, which will allow Duke Energy Florida to use the tax savings resulting from the Tax Act to recover these storm costs in lieu of implementing a storm surcharge. Approved storm costs are currently expected to be fully recovered by approximately year-end 2021. On November 22, 2019, Duke Energy Florida filed a petition for approval of actual retail recoverable storm restoration costs related to Hurricane Michael in the amount of $191 million plus interest. An Order Establishing Procedure was issued on January 30, 2020, and hearings are scheduled to begin September 15, 2020. Duke Energy Florida cannot predict the outcome of this matter.

Hurricane Dorian

In September 2019, Duke Energy Florida's service territory was threatened by Hurricane Dorian with landfall as a possible Category 5 hurricane. For several days, various forecasts and models predicted significant impact to Duke Energy Florida's service territory; accordingly, Duke Energy Florida incurred costs to secure necessary resources to be prepared for that potential impact. Although Hurricane Dorian never made landfall in Florida, its effects were still felt, and outages did occur. Preparations were required so that, if Hurricane Dorian had made landfall and impacts had been more severe, Duke Energy Florida would have been prepared to restore its customers' power in a timely fashion.

Total current estimated incremental costs are approximately $167 million. These costs are included in Regulatory assets within Current Assets and Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019, representing recoverable costs under the FPSC's storm rule and Duke Energy Florida's OATT formula rates. On December 19, 2019, Duke Energy Florida filed a petition with the FPSC to recover the estimated retail portion of these costs, consistent with the provisions in the 2017 Settlement. The request seeks recovery over a 12-month period beginning in March 2020. The final actual amount will be filed later in 2020 and a hearing will be held at the FPSC to determine the final amount of incremental costs. Duke Energy Florida cannot predict the outcome of this matter.

Tax Act

Pursuant to Duke Energy Florida's 2017 Settlement, on May 31, 2018, Duke Energy Florida filed a petition related to the Tax Act, which included revenue requirement impacts of annual tax savings of $134 million and estimated annual amortization of EDIT of $67 million for a total of $201 million. Of this amount, $50 million would be offset by accelerated depreciation of Crystal River 4 and 5 coal units and an estimated $151 million would be offset by Hurricane Irma storm cost recovery as explained in the Storm Restoration Cost Recovery section above. On December 27, 2018, Duke Energy Florida filed actual EDIT balances and amortization based on its 2017 filed tax return. This increased the revenue requirement impact of the amortization of EDIT by $4 million, from $67 million to $71 million, which increased the total storm amortization from $151 million to $155 million. On January 8, 2019, the FPSC approved a joint motion by Duke Energy Florida and the Office of Public Counsel resolving all stipulated positions. As part of that stipulation, Duke Energy Florida agreed to seek a Private Letter Ruling (PLR) from the IRS on its treatment of cost of removal (COR) as mostly protected by tax normalization rules. If the IRS rules that COR is not protected by tax normalization rules, then Duke Energy Florida will make a final adjustment to the amortization of EDIT and an adjustment to the storm recovery amount retroactive to January 2018. The IRS has communicated that it will not issue individual PLRs on the treatment of COR. Rather, the IRS is drafting a notice that will request comments on a number of issues, including COR, and the IRS plans to issue industrywide guidance on those issues. Duke Energy Florida cannot predict the outcome of this matter.

Citrus County CC

Construction of the 1,640-MW combined-cycle natural gas plant in Citrus County, Florida, began in October 2015 with an estimated cost of $1.5 billion, including AFUDC. Both units came on-line in the fourth quarter of 2018. The ultimate cost of the facility was estimated to be $1.6 billion, and Duke Energy Florida recorded Impairment charges on Duke Energy's Consolidated Statements of Operations of $60 million in the fourth quarter of 2018 for the overrun. In the year ended December 31, 2019, Duke Energy Florida recorded a $36 million reduction to the prior-year impairment due to a decrease in the cost estimate of the Citrus County CC, primarily related to the settlement agreement with Fluor, the EPC contractor. This adjustment reduced the estimated cost of the facility to $1.5 billion.

Solar Base Rate Adjustment

On July 31, 2018, Duke Energy Florida petitioned the FPSC to include in base rates the revenue requirements for its first two solar generation projects, the Hamilton Project and the Columbia Project, as authorized by the 2017 Settlement. The Hamilton Project, which was placed into service on December 22, 2018, has an annual retail revenue requirement of $15 million. At its October 30, 2018, Agenda Conference, the FPSC approved the rate increase related to the Hamilton Project to go into effect beginning with the first billing cycle in January 2019 under its file and suspend authority, and revised customer rates became effective in January 2019. The Columbia Project has a projected annual revenue requirement of $14 million and a projected in-service date in early 2020; the associated rate increase would take place with the first month's billing cycle after the Columbia Project goes into service. On April 2, 2019, the commission approved both solar projects as filed.

On March 25, 2019, Duke Energy Florida petitioned the FPSC to include in base rates the revenue requirements for its next wave of solar generation projects, the Trenton, Lake Placid and DeBary Solar Projects, as authorized by the 2017 Settlement. The annual retail revenue requirement for the Trenton and Lake Placid Projects is $13 million and $8 million, respectively, and were placed into service in December 2019 with rates taking effect in January 2020. The DeBary Project has a projected annual revenue requirement of $11 million and a projected in-service date in the first half of 2020. The associated rate increase would take place with the first month's billing cycle after each solar generation project goes into service. On July 22, 2019, the FPSC issued an order approving Duke Energy Florida's request.

Crystal River Unit 3 Accelerated Decommissioning Filing

On May 29, 2019, Duke Energy Florida entered into a Decommissioning Services Agreement for the accelerated decommissioning of the Crystal River Unit 3 nuclear power station located in Citrus County, Florida, with ADP CR3, LLC and ADP SF1, LLC, each of which is a wholly owned subsidiary of Accelerated Decommissioning Partners, LLC, a joint venture between NorthStar Group Services, Inc. and Orano USA LLC. Closing of this agreement is contingent upon the approval of the NRC and FPSC. If approved, the decommissioning will be accelerated starting in 2020 and continuing through 2027, rather than the expected time frame under SAFSTOR of starting in 2067 and ending in 2074. Duke Energy Florida expects that the assets of the Nuclear Decommissioning Trust Fund will be sufficient to cover the contract price. On July 10, 2019, Duke Energy Florida petitioned the FPSC for approval of the agreement. Duke Energy Florida cannot predict the outcome of this matter.

Duke Energy Ohio

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Ohio's Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	$ 16	$ 20	Yes	(b)
Accrued pension and OPEB	155	146		(g)
Storm cost deferrals	7	4		2023
Deferred fuel and purchased power	1	2		2020
Hedge costs deferrals	6	5		(b)
DSM/EE	2	10	(f)	(e)
AMI	40	46		(b)
PISCC and deferred operating expenses[c]	17	17	Yes	2083
Vacation accrual	5	5		2020
MGP	102	99		(b)
Deferred pipeline integrity costs	17	14	Yes	(b)
East Bend deferrals	44	47	Yes	(b)
Transmission expansion obligation	40	43		(e)
Grid modernization	28	31	Yes	(b) (c)
Other	118	75		(b)
Total regulatory assets	598	564		
Less: current portion	49	33		
Total noncurrent regulatory assets	$ 549	$ 531		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	$ 654	$ 678		(b)
Costs of removal	86	126		(d)
Accrued pension and OPEB	16	18		(g)
Other	71	75		(b)
Total regulatory liabilities	827	897		
Less: current portion	64	57		
Total noncurrent regulatory liabilities	$ 763	$ 840		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Recovered via a rider mechanism.
(f) Includes incentives on DSM/EE investments.

(g) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

2017 Electric Security Plan Filing

On June 1, 2017, Duke Energy Ohio filed with the PUCO a request for a standard service offer in the form of an Electric Security Plan (ESP). On February 15, 2018, the procedural schedule was suspended to facilitate ongoing settlement discussions. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases pending before the PUCO, including, but not limited to, its Electric Base Rate Case. Additionally, on April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed a Stipulation and Recommendation (Stipulation) with the PUCO resolving certain issues in this proceeding. The term of the ESP would be from June 1, 2018, to May 31, 2025, and included continuation of market-based customer rates through competitive procurement processes for generation, continuation and expansion of existing rider mechanisms and proposed new rider mechanisms relating to regulatory mandates, costs incurred to enhance the customer experience and transform the grid and a service reliability rider for vegetation management. The Stipulation established a regulatory model for the next seven years via the approval of the ESP and continued the current model for procuring supply for non-shopping customers, including recovery mechanisms. On December 19, 2018, the PUCO approved the Stipulation without material modification. Several parties, including the OCC, filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

Electric Base Rate Case

Duke Energy Ohio filed with the PUCO an electric distribution base rate case application and supporting testimony in March 2017. Duke Energy Ohio requested an estimated annual increase of approximately $15 million and a return on equity of 10.4%. The application also included requests to continue certain current riders and establish new riders. On September 26, 2017, the PUCO staff filed a report recommending a revenue decrease between approximately $18 million and $29 million and a return on equity between 9.22% and 10.24%. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases pending before the PUCO. On April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed the Stipulation with the PUCO resolving numerous issues including those in this base rate proceeding. Major components of the Stipulation related to the base distribution rate case included a $19 million decrease in annual base distribution revenue with a return on equity unchanged from the current rate of 9.84% based upon a capital structure of 50.75% equity and 49.25% debt. Upon approval of new rates, Duke Energy Ohio's rider for recovering its initial SmartGrid implementation ended as these costs would be recovered through base rates. The Stipulation also renewed 14 existing riders, some of which were included in the company's ESP, and added two new riders including the Enhanced Service Reliability Rider to recover vegetation management costs not included in base rates, up to $10 million per year (operation and maintenance only) and the PowerForward Rider to recover costs incurred to enhance the customer experience and further transform the grid (operation and maintenance and capital). In addition to the changes in revenue attributable to the Stipulation, Duke Energy Ohio's capital-related riders, including the Distribution Capital Investments Rider, began to reflect the lower federal income tax rate associated with the Tax Act with updates to customers' bills beginning April 1, 2018. This change reduced electric revenue by approximately $20 million on an annualized basis. On December 19, 2018, the PUCO approved the Stipulation without material modification. New base rates were implemented effective January 2, 2019. Several parties including the OCC filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

Ohio Valley Electric Corporation

On March 31, 2017, Duke Energy Ohio filed for approval to adjust its existing Rider PSR to pass through net costs related to its contractual entitlement to capacity and energy from the generating assets owned by OVEC. Duke Energy Ohio sought deferral authority for net costs incurred from April 1, 2017, until the new rates under Rider PSR were put into effect. On April 13, 2018, Duke Energy Ohio filed a Motion to consolidate this proceeding with several other cases currently pending before the PUCO. Also, on April 13, 2018, Duke Energy Ohio, along with certain intervenors, filed a Stipulation with the PUCO resolving numerous issues including those related to Rider PSR. The Stipulation activated Rider PSR for recovery of net costs incurred from January 1, 2018, through May 2025. On December 19, 2018, the PUCO approved the Stipulation without material modification. The PSR rider became effective April 1, 2019. Several parties, including the OCC, filed applications for rehearing. On February 6, 2019, the PUCO granted the parties rehearing. The PUCO issued its Second Entry on Rehearing on July 17, 2019, upholding its December 19, 2018, order and denying all assignments of error raised by the non-stipulating parties. On October 11, 2019, the OCC filed its Third Application for Rehearing arguing the PUCO erred in finding OCC's Second Application for Rehearing as improper. Duke Energy Ohio filed its Memorandum Contra on October 21, 2019. The PUCO denied OCC's Third Application for Rehearing as a matter of law. On September 13, 2019, Interstate Gas Supply/Retail Supply Association filed appeals to the Ohio Supreme Court claiming the PUCO's order was in error because it approved unsupported charges to competitive suppliers and cost subsidies shopping customers pay for non-shopping customers. On September 16, 2019, the OCC filed an appeal challenging the PUCO's approval of OVEC recovery through Rider PSR alleging the FPA pre-empts the commission's jurisdiction and that the record does not support finding that Rider PSR results in a limitation on shopping. Appellant briefs were filed on January 6, 2020. Appellee briefs will be due March 16, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

On July 23, 2019, an Ohio bill was signed into law that became effective January 1, 2020. Among other things, the bill allows for recovery of prudently incurred costs, net of any revenues, for Ohio investor-owned utilities that are participants under the OVEC power agreement. The recovery shall be through a non-bypassable rider that is to replace any existing recovery mechanism approved by the PUCO and will remain in place through 2030. The amounts recoverable from customers will be subject to an annual cap, with incremental costs that exceed such cap eligible for deferral and recovery subject to review. See Note 18 for additional discussion of Duke Energy Ohio's ownership interest in OVEC.

Tax Act – Ohio

On July 25, 2018, Duke Energy Ohio filed an application to establish a new rider to implement the benefits of the Tax Act for electric distribution customers. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35% to 21% since January 1, 2018, all future benefits of the lower tax rates and a full refund of deferred income taxes collected at the higher tax rates in prior years. Deferred income taxes subject to normalization rules will be refunded consistent with federal law and deferred income taxes not subject to normalization rules will be refunded over a 10-year period. Duke Energy Ohio's transmission rates reflect lower federal income tax but guidance from FERC on amortization of both protected and unprotected transmission-related EDITs is still pending. On October 24, 2018, the PUCO issued a Finding and Order that, among other things, directed all utilities over which the commission has ratemaking authority to file an application to pass the benefits of the Tax Act to customers by January 1, 2019, unless otherwise exempted or directed by the PUCO. Duke Energy Ohio's July 25, 2018, filing for electric distribution operations is consistent with the commission's October 24, 2018, Finding and Order and no further action is needed. On February 20, 2019, the PUCO approved the application without material modification. Rates became effective March 1, 2019.

On December 21, 2018, Duke Energy Ohio filed an application to change its base rates and establish a new rider to implement the benefits of the Tax Act for natural gas customers. Duke Energy Ohio requested commission approval to implement the changes and rider effective April 1, 2019. The new rider will flow through to customers the benefit of the lower statutory federal tax rate from 35% to 21% since January 1, 2018, all future benefits of the lower tax rates and a full refund of deferred income taxes collected at the higher tax rates in prior years. Deferred income taxes subject to normalization rules will be refunded consistent with federal law and deferred income taxes not subject to normalization rules will be refunded over a 10-year period. The PUCO established a procedural schedule and testimony was filed on July 31, 2019. An evidentiary hearing occurred on August 7, 2019. Initial briefs were filed on September 11, 2019. Reply briefs were filed on September 25, 2019. Duke Energy Ohio cannot predict the outcome of this matter.

Energy Efficiency Cost Recovery

On March 28, 2014, Duke Energy Ohio filed an application for recovery of program costs, lost distribution revenue and performance incentives related to its energy efficiency and peak demand reduction programs. These programs are undertaken to comply with environmental mandates set forth in Ohio law. The PUCO approved Duke Energy Ohio's application but found that Duke Energy Ohio was not permitted to use banked energy savings from previous years in order to calculate the amount of allowed incentive. This conclusion represented a change to the cost recovery mechanism that had been agreed upon by intervenors and approved by the PUCO in previous cases. The PUCO granted the applications for rehearing filed by Duke Energy Ohio and an intervenor. On January 6, 2016, Duke Energy Ohio and the PUCO Staff entered into a stipulation, pending the PUCO's approval, to resolve issues related to performance incentives and the PUCO Staff audit of 2013 costs, among other issues. In December 2015, based upon the stipulation, Duke Energy Ohio re-established approximately $20 million of the revenues that had been previously reversed. On October 26, 2016, the PUCO issued an order approving the stipulation without modification. In December 2016, the PUCO granted the intervenors request for rehearing for the purpose of further review. On April 10, 2019, the PUCO issued an Entry on Rehearing denying the rehearing applications.

On June 15, 2016, Duke Energy Ohio filed an application for approval of a three-year energy efficiency and peak demand reduction portfolio of programs. A stipulation and modified stipulation were filed on December 22, 2016, and January 27, 2017, respectively. Under the terms of the stipulations, which included support for deferral authority of all costs and a cap on shared savings incentives, Duke Energy Ohio has offered its energy efficiency and peak demand reduction programs throughout 2017. On February 3, 2017, Duke Energy Ohio filed for deferral authority of its costs incurred in 2017 in respect of its proposed energy efficiency and peak demand reduction portfolio. On September 27, 2017, the PUCO issued an order approving a modified stipulation. The modifications impose an annual cap of approximately $38 million on program costs and shared savings incentives combined, but allowed for Duke Energy Ohio to file for a waiver of costs in excess of the cap in 2017. The PUCO approved the waiver request for 2017 up to a total cost of $56 million. On November 21, 2017, the PUCO granted Duke Energy Ohio's and intervenor's applications for rehearing of the September 27, 2017, order. On January 10, 2018, the PUCO denied the OCC's application for rehearing of the PUCO order granting Duke Energy Ohio's waiver request; however, a decision on Duke Energy Ohio's application for rehearing remains pending. On October 15, 2019, the Ohio Supreme Court issued an Opinion regarding a similar cap on energy efficiency imposed by the PUCO on Ohio Edison Company finding the PUCO lacked statutory authority to impose a cap on cost recovery. On December 9, 2019, and in response to recent changes to Ohio Law, the OCC filed a motion to eliminate shared savings from Duke Energy Ohio's energy efficiency calculation beginning in 2020. Duke Energy Ohio filed a memorandum contra and a notice of additional authority on December 16, 2019, arguing OCC's interpretation is incorrect and that the commission should amend its September 27, 2017 order to comply with recent precedent. Duke Energy Ohio cannot predict the outcome of this matter.

2014 Electric Security Plan

On May 30, 2018, the PUCO approved an extension of Duke Energy Ohio's then-current ESP, including all terms and conditions thereof, excluding an extension of Duke Energy Ohio's Distribution Capital Investment Rider. Following rehearing, on July 25, 2018, the PUCO granted the request and allowed a continuing cap on recovery under Rider DCI. The orders were upheld on rehearing requested by the Ohio Manufacturers' Association (OMA) and OCC. The time period for parties to file for rehearing or appeal has expired.

In 2018, the OMA and OCC filed separate appeals of PUCO's approval of Duke Energy Ohio's ESP with the Ohio Supreme Court, challenging PUCO's approval of Duke Energy Ohio's Rider PSR as a placeholder and its Rider DCI to recover incremental revenue requirement for distribution capital since Duke Energy Ohio's last base rate case. The Ohio Supreme Court issued an order on March 13, 2019, for the appellants to show cause why the appeals should not be dismissed as moot in light of the commission's approval of Duke Energy Ohio's current ESP. The OCC and OMA made the requested filings on March 20, 2019, and Duke Energy Ohio filed its response on March 27, 2019. Subsequent to OCC and OMA making the requested filings, the Ohio Supreme Court dismissed the appeals as moot on May 8, 2019.

Natural Gas Pipeline Extension

Duke Energy Ohio is proposing to install a new natural gas pipeline (the Central Corridor Project) in its Ohio service territory to increase system reliability and enable the retirement of older infrastructure. Duke Energy Ohio currently estimates the pipeline development costs and construction activities will range from $163 million to $245 million in direct costs (excluding overheads and AFUDC). On January 20, 2017, Duke Energy Ohio filed an amended application with the Ohio Power Siting Board (OPSB) for approval of one of two proposed routes. A public hearing was held on June 15, 2017. In April 2018, Duke Energy Ohio filed a motion with OPSB to establish a procedural schedule and filed supplemental information supporting its application. On December 18, 2018, the OPSB established a procedural schedule that included a local public hearing on March 21, 2019. An evidentiary hearing began on April 9, 2019, and concluded on April 11, 2019. Briefs were filed on May 13, 2019, and reply briefs were filed on June 10, 2019. On November 21, 2019, the OPSB approved Duke Energy Ohio's application subject to 41 conditions on construction. Applications for rehearing were filed by several stakeholders on December 23, 2019, arguing that the OPSB approval was incorrect. Duke Energy Ohio filed a memorandum contra on January 2, 2020. On January 17, 2020, the OPSB granted rehearing for the purpose of further consideration. Construction of the pipeline extension is expected to be completed before the 2021/2022 winter season. Duke Energy Ohio cannot predict the outcome of this matter.

2012 Natural Gas Rate Case/MGP Cost Recovery

As part of its 2012 natural gas base rate case, Duke Energy Ohio has approval to defer and recover costs related to environmental remediation at two sites (East End and West End) that housed former MGP operations. Duke Energy Ohio has made annual applications for recovery of these deferred costs. Duke Energy Ohio has collected approximately $55 million in environmental remediation costs between 2009 through 2012 through a separate rider, Rider MGP, which is currently suspended. Duke Energy Ohio has made annual applications with the PUCO to recover its incremental remediation costs consistent with the PUCO's directive in Duke Energy Ohio's 2012 natural gas rate case. To date, the PUCO has not ruled on Duke Energy Ohio's annual applications for the calendar years 2013 through 2017. On September 28, 2018, the staff of the PUCO issued a report recommending a disallowance of approximately $12 million of the $26 million in MGP remediation costs incurred between 2013 through 2017 that staff believes are not eligible for recovery. Staff interprets the PUCO's 2012 Order granting Duke Energy Ohio recovery of MGP remediation as limiting the recovery to work directly on the East End and West End sites. On October 30, 2018, Duke Energy Ohio filed reply comments objecting to the staff's recommendations and explaining, among other things, the obligation Duke Energy Ohio has under Ohio law to remediate all areas impacted by the former MGPs and not just physical property that housed the former plants and equipment. To date, the PUCO has not ruled on Duke Energy Ohio's applications. On March 29, 2019, Duke Energy Ohio filed its annual application to recover incremental remediation expense for the calendar year 2018 seeking recovery of approximately $20 million in remediation costs. On July 12, 2019, the staff recommended a disallowance of approximately $11 million for work that staff believes occurred in areas not authorized for recovery. Additionally, staff recommended that any discussion pertaining to Duke Energy Ohio's recovery of ongoing MGP costs should be directly tied to or netted against insurance proceeds collected by Duke Energy Ohio. An evidentiary hearing began on November 18, 2019, and concluded November 21, 2019. Initial briefs were filed on January 17, 2020, and reply briefs were filed on February 14, 2020. Duke Energy Ohio cannot predict the outcome of this matter.

The 2012 PUCO order also contained conditional deadlines for completing the MGP environmental investigation and remediation costs at the MGP sites. Subsequent to the order, the deadline was extended to December 31, 2019. On May 10, 2019, Duke Energy Ohio filed an application requesting a continuation of its existing deferral authority for MGP remediation and investigation that must occur after December 31, 2019. On September 13, 2019, intervenor comments were filed opposing Duke Energy Ohio's request for continuation of existing deferral authority and on October 2, 2019, Duke Energy Ohio filed reply comments. Duke Energy Ohio cannot predict the outcome of this matter.

Duke Energy Kentucky Natural Gas Base Rate Case

On August 31, 2018, Duke Energy Kentucky filed an application with the KPSC requesting an increase in natural gas base rates of approximately $11 million, an approximate 11.1% average increase across all customer classes. The increase was net of approximately $5 million in annual savings as a result of the Tax Act. The drivers for this case were capital invested since Duke Energy Kentucky's last rate case in 2009. Duke Energy Kentucky also sought implementation of a Weather Normalization Adjustment Mechanism, amortization of regulatory assets and to implement the impacts of the Tax Act, prospectively. On January 30, 2019, Duke Energy Kentucky entered into a settlement agreement with the Attorney General of Kentucky, the only intervenor in the case. The settlement provided for an approximate $7 million increase in natural gas base revenue, a return on equity of 9.7% and approval of the proposed Weather Normalization Mechanism. A hearing was held on February 5, 2019. The commission issued its order approving the settlement without material modification on March 27, 2019. Revised customer rates were effective April 1, 2019.

Duke Energy Kentucky Electric Base Rate Case

On September 3, 2019, Duke Energy Kentucky filed a rate case with the KPSC requesting an increase in electric base rates of approximately $46 million, which represents an approximate 12.5% increase across all customer classes. The request for rate increase is driven by increased investment in utility plant since the last electric base rate case in 2017. Duke Energy Kentucky seeks to implement a Storm Deferral Mechanism that will enable Duke Energy Kentucky to defer actual costs incurred for major storms that are over or under amounts in base rates. In response to large customers' desire to have access to renewable resources, Duke Energy Kentucky is proposing a Green Source Advantage tariff designed for those large customers that wish to invest in renewable energy resources to meet sustainability goals. Duke Energy Kentucky is proposing an electric vehicle (EV) infrastructure pilot and modest incentives to assist customers in investing in EV technologies. Additionally, Duke Energy Kentucky is proposing to build an approximate 3.4 MW distribution battery energy storage system to be attached to Duke Energy Kentucky's distribution system providing frequency regulation and enhanced reliability to Kentucky customers. The commission issued a procedural schedule with two rounds of discovery and opportunities for intervenor and rebuttal testimony. The Kentucky Attorney General filed its testimony recommending an increase of approximately $26 million. On January 31, 2020, Duke Energy Kentucky filed rebuttal testimony updating its rate increase calculations to approximately $44 million. Hearings began on February 19, 2020. Duke Energy Kentucky anticipates that rates will go into effect in the second quarter of 2020. Duke Energy Kentucky cannot predict the outcome of this matter.

Regional Transmission Organization Realignment

Duke Energy Ohio, including Duke Energy Kentucky, transferred control of its transmission assets from MISO to PJM, effective December 31, 2011. The PUCO approved a settlement related to Duke Energy Ohio's recovery of certain costs of the RTO realignment via a non-bypassable rider. Duke Energy Ohio is allowed to recover all MISO Transmission Expansion Planning (MTEP) costs directly or indirectly charged to Ohio customers. The KPSC also approved a request to effect the RTO realignment, subject to a commitment not to seek double recovery in a future rate case of the transmission expansion fees that may be charged by MISO and PJM in the same period or overlapping periods.

The following table provides a reconciliation of the beginning and ending balance of Duke Energy Ohio's recorded liability for its exit obligation and share of MTEP costs recorded in Other within Current Liabilities and Other Noncurrent Liabilities on the Consolidated Balance Sheets. The retail portions of MTEP costs billed by MISO are recovered by Duke Energy Ohio through a non-bypassable rider. As of December 31, 2019, and 2018, $40 million and $43 million, respectively, are recorded in Regulatory assets on Duke Energy Ohio's Consolidated Balance Sheets.

(in millions)	**December 31, 2018**	**Provisions/ Adjustments**	**Cash Reductions**	**December 31, 2019**
Duke Energy Ohio	$ 58	**$ —**	**$ (4)**	**$ 54**

Duke Energy Indiana

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Duke Energy Indiana's Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – coal ash	**$ 529**	$ 450		(b)
Accrued pension and OPEB	**243**	222		(f)
Deferred fuel and purchased power	**—**	40		2020
Hedge costs deferrals	**23**	24		(b)
DSM/EE	**—**	14	(e)	(e)
AMI[c]	**18**	18	Yes	(b)
Retired generation facilities[c]	**49**	57	Yes	2026
PISCC and deferred operating expenses[c]	**246**	233	Yes	(b)
Vacation accrual	**12**	11		2020
Other	**52**	88		(b)
Total regulatory assets	**1,172**	1,157		
Less: current portion	**90**	175		
Total noncurrent regulatory assets	**$ 1,082**	$ 982		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	**$ 1,008**	$ 1,009		(b)
Costs of removal	**599**	628		(d)
Accrued pension and OPEB	**90**	67		(f)
Amounts to be refunded to customers	**—**	1		2020
Other	**43**	42		(b)
Total regulatory liabilities	**1,740**	1,747		
Less: current portion	**55**	25		
Total noncurrent regulatory liabilities	**$ 1,685**	$ 1,722		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Refunded over the life of the associated assets.
(e) Includes incentives on DSM/EE investments and is recovered through a tracker mechanism over a two-year period.
(f) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

2019 Indiana Rate Case

On July 2, 2019, Duke Energy Indiana filed a general rate case with the IURC, its first general rate case in Indiana in 16 years, for a rate increase for retail customers of approximately $395 million. The request for rate increase is driven by strategic investments to generate cleaner electricity, improve reliability and serve a growing customer base. The request is premised upon a Duke Energy Indiana rate base of $10.2 billion as of December 31, 2018, and adjusted for projected changes through December 31, 2020. On September 9, 2019, Duke Energy Indiana revised its revenue request from $395 million to $393 million and filed updated testimony for the Retail Rate Case. The updated filing reflects a clarification in the presentation of Utility Receipts Tax, a $2 million reduction in the revenue requirement for revenues that will remain in riders and changes to allocation of revenue requirements within rate classes. The Utility Receipts Tax is currently embedded in base rates and rider rates. The proposed treatment is to include the Utility Receipts Tax as a line item on the customer bill rather than included in rates. The request is an approximate 15% increase in retail revenues and approximately 17% when including estimated Utility Receipts Tax. The rebuttal case, filed on December 4, 2019, updated the requested revenue requirement to result in a 15.6% or $396 million average retail rate increase, including the impacts of the Utility Receipts Tax. The commission determined to take two issues out of the rate case and place them in separate subdocket proceedings due to the complexity of the rate case. The commission moved the request for electric transportation pilot and future coal ash recovery issues to separate subdockets. Coal ash expenditures prior to 2019 are still included in the rate case. Hearings concluded on February 7, 2020 and rates are expected to be effective by mid-2020. Duke Energy Indiana cannot predict the outcome of these matters.

Edwardsport IGCC Plant

On September 20, 2018, Duke Energy Indiana, the Indiana Office of Utility Consumer Counselor, the Duke Industrial Group and Nucor Steel – Indiana entered into a settlement agreement to resolve IGCC ratemaking issues for calendar years 2018 and 2019. The agreement will remain in effect until new rates are established in Duke Energy Indiana's next base rate case, which was filed on July 2, 2019, with rates to be effective in mid-2020. An evidentiary hearing was held in December 2018, and on June 5, 2019, the IURC issued an order approving the 2018 Settlement Agreement.

Piedmont

Regulatory Assets and Liabilities

The following tables present the regulatory assets and liabilities recorded on Piedmont's Consolidated Balance Sheets.

(in millions)	December 31, 2019	December 31, 2018	Earns/Pays a Return	Recovery/Refund Period Ends
Regulatory Assets[a]				
AROs – nuclear and other	**16**	19		(d)
Accrued pension and OPEB[c]	**90**	99	Yes	(f)
Vacation accrual	**12**	12		
Derivatives – natural gas supply contracts[e]	**117**	141		
Deferred pipeline integrity costs[c]	**62**	51	Yes	(b)
Amounts due from customers	**36**	24	Yes	(b)
Other	**30**	11		(b)
Total regulatory assets	**363**	357		
Less: current portion	**73**	54		
Total noncurrent regulatory assets	**$ 290**	$ 303		
Regulatory Liabilities[a]				
Net regulatory liability related to income taxes	**$ 555**	$ 579		(b)
Costs of removal	**574**	564		(d)
Accrued pension and OPEB[c]	**3**	1	Yes	(f)
Amounts to be refunded to customers	**34**	33	Yes	(b)
Other	**46**	41		(b)
Total regulatory liabilities	**1,212**	1,218		
Less: current portion	**81**	37		
Total noncurrent regulatory liabilities	**$ 1,131**	$ 1,181		

(a) Regulatory assets and liabilities are excluded from rate base unless otherwise noted.
(b) The expected recovery or refund period varies or has not been determined.
(c) Included in rate base.
(d) Recovery over the life of the associated assets.
(e) Balance will fluctuate with changes in the market. Current contracts extend into 2031.
(f) Recovered primarily over the average remaining service periods or life expectancies of employees covered by the benefit plans. See Note 23 for additional detail.

North Carolina Integrity Management Rider Filing

On April 30, 2019, Piedmont filed a petition under the IMR mechanism to update rates, based on the eligible capital investments closed to integrity and safety projects over the six-month period ending March 31, 2019. The NCUC approved the petition on May 29, 2019, and rates became effective June 1, 2019. The effect of the update was an increase to annual revenues of approximately $9 million. These revenues, along with eligible spending for the three months ended June 30, 2019, were subsequently included in base rates effective November 1, 2019, as part of the 2019 North Carolina Rate Case.

On October 31, 2019, Piedmont filed a petition under the IMR mechanism to update rates, based on the eligible capital investments closed to integrity and safety projects over the three-month period ending September 30, 2019. The NCUC approved the petition on December 3, 2019, and rates became effective December 1, 2019. The effect of the update was an increase to annual revenues of approximately $11 million.

Tennessee Integrity Management Rider Filing

In November 2019, Piedmont filed a petition with the TPUC under the IMR mechanism to collect an additional $4 million in annual revenues, effective January 2020, based on the eligible capital spending on integrity and safety projects over the 12-month period ending October 31, 2019. A procedural schedule has not yet been set for this matter. Piedmont cannot predict the outcome of this matter.

2019 North Carolina Rate Case

On April 1, 2019, Piedmont filed an application with the NCUC, its first general rate case in North Carolina in six years, for a rate increase for retail customers of approximately $83 million, which represents an approximate 9% increase in retail revenues. The request for rate increase was driven by significant infrastructure upgrade investments (plant additions) since the last general rate case through June 30, 2019, offset by savings that customers will begin receiving due to federal and state tax reform. Approximately half of the plant additions being included in rate base are categories of plant investment not covered under the IMR mechanism, which was originally approved as part of the 2013 North Carolina Rate Case.

On August 13, 2019, Piedmont, the Public Staff, and two groups representing industrial customers filed an Agreement and Stipulation Settlement resolving issues in the base rate proceeding, which included a return on equity of 9.7% and a capital structure of 52% equity and 48% debt. The North Carolina Attorney General's Office did not support the settlement. Other major components of the Stipulation included:

- An annual increase in revenues of $109 million before consideration of riders associated with federal and state tax reform;
- A decrease through a rider mechanism of $23 million per year to return unprotected federal EDIT over a five-year period and deferred revenues related to the federal rate reduction of $37 million to be returned over one year;
- A decrease through a rider mechanism of $21 million per year related to reductions in the North Carolina state income tax rate to be returned over a three-year period;
- An overall cap on net revenue increase of $83 million. This will impact Piedmont beginning November 1, 2022, only if the company does not file another general rate case in the interim;
- Continuation of the IMR mechanism; and
- Establishment of a new deferral mechanism for certain Distribution Integrity Management Program (DIMP) operations and maintenance expenses incurred effective November 1, 2019, and thereafter.

An evidentiary hearing began on August 19, 2019. On October 31, 2019, the NCUC approved the Stipulation and the revised customer rates were effective November 1, 2019.

OTHER REGULATORY MATTERS

Atlantic Coast Pipeline, LLC

On September 2, 2014, Duke Energy, Dominion Energy, Inc. (Dominion), Piedmont and Southern Company Gas announced the formation of Atlantic Coast Pipeline, LLC (ACP) to build and own the proposed Atlantic Coast Pipeline (ACP pipeline), an approximately 600-mile interstate natural gas pipeline running from West Virginia to North Carolina. The ACP pipeline is designed to meet, in part, the needs identified by Duke Energy Carolinas, Duke Energy Progress and Piedmont. Dominion will be responsible for building and operating the ACP pipeline and holds a leading ownership percentage in ACP of 48%. Duke Energy owns a 47% interest, which is accounted for as an equity method investment through its Gas Utilities and Infrastructure segment. Southern Company Gas maintains a 5% interest. See Notes 13 and 18 for additional information related to Duke Energy's ownership interest. Duke Energy Carolinas, Duke Energy Progress and Piedmont, among others, will be customers of the pipeline. Purchases will be made under several 20-year supply contracts, subject to state regulatory approval.

In 2018, the FERC issued a series of Notices to Proceed, which authorized the project to begin certain construction-related activities along the pipeline route, including supply header and compressors. On May 11, 2018, and October 19, 2018, FERC issued Notices to Proceed allowing full construction activities in all areas of West Virginia except in the Monongahela National Forest. On July 24, 2018, FERC issued a Notice to Proceed allowing full construction activities along the project route in North Carolina. On October 19, 2018, the conditions to effectiveness of the Virginia 401 water quality certification were satisfied and, following receipt of the Virginia 401 certification, ACP filed a request for FERC to issue a Notice to Proceed with full construction activities in Virginia. Due to legal challenges not directly related to the request for a Notice to Proceed in Virginia, this request is still pending.

ACP is the subject of challenges in state and federal courts and agencies, including, among others, challenges of the project's biological opinion (BiOp) and incidental take statement (ITS), crossings of the Blue Ridge Parkway, the Appalachian Trail, and the Monongahela and George Washington National Forests, the project's U.S. Army Corps of Engineers (USACE) 404 permit, the project's air permit for a compressor station at Buckingham, Virginia, the FERC Environmental Impact Statement order and the FERC order approving the Certificate of Public Convenience and Necessity. Each of these challenges alleges non-compliance on the part of federal and state permitting authorities and adverse ecological consequences if the project is permitted to proceed. Since December 2018, notable developments in these challenges include a stay in December 2018 issued by the U.S. Court of Appeals for the Fourth Circuit (Fourth Circuit) and the same court's July 26, 2019, vacatur of the project's BiOp and ITS (which stay and subsequent vacatur halted most project construction activity), a Fourth Circuit decision vacating the project's permits to cross the Monongahela and George Washington National Forests and the Appalachian Trail, the Fourth Circuit's remand to USACE of ACP's Huntington District 404 verification, the Fourth Circuit's remand to the National Park Service of ACP's Blue Ridge Parkway right-of-way and the most recent vacatur of the air permit for a compressor station at Buckingham, Virginia. ACP is vigorously defending these challenges and coordinating with the federal and state authorities which are the direct parties to the challenges. The Solicitor General of the United States and ACP filed petitions for certiorari to the Supreme Court of the United States on June 25, 2019, regarding the Appalachian Trail crossing and certiorari was granted on October 4, 2019. The Supreme Court hearing is scheduled for February 24, 2020, and a ruling is expected in the second quarter of 2020. ACP is also evaluating possible legislative and other remedies to this issue.

In anticipation of the Fourth Circuit's vacatur of the BiOp and ITS, ACP and the FWS commenced work in mid-May of 2019 to set the basis for a reissued BiOp and ITS. On February 10, 2020, FERC issued a letter to FWS requesting the re-initiation of formal consultation in support of reissuing the BiOp and ITS. ACP continues coordinating and working with FWS and other parties in preparation for a reissuance of the BiOp and ITS.

ACP triggered the Adverse Government Actions (AGA) clause of its agreements with its customers in December 2019. Formal negotiations have commenced regarding pricing and construction timing, among other items, and are expected to be finalized in the first quarter of 2020. The results of these negotiations will directly impact the expected future cash flows of this project.

Given the legal challenges and ongoing discussions with customers, ACP expects mechanical completion of the full project in late 2021 with in-service likely in the first half of 2022.

The delays resulting from the legal challenges described above have also impacted the cost for the project. Project cost is approximately $8 billion, excluding financing costs. This estimate is based on the current facts available around construction costs and timelines, and is subject to future changes as those facts develop. Abnormal weather, work delays (including delays due to judicial or regulatory action) and other conditions may result in cost or schedule modifications, a suspension of AFUDC for ACP and/or impairment charges potentially material to Duke Energy's cash flows, financial position and results of operations.

Duke Energy's investment in ACP was $1.2 billion at December 31, 2019. Duke Energy evaluated this investment for impairment at December 31, 2019, and determined that fair value approximated carrying value and therefore no impairment was necessary. Duke Energy also has a guarantee agreement supporting its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $827 million, which represents 47% of the outstanding borrowings under the credit facility as of December 31, 2019. See Note 13 for additional information.

Constitution Pipeline Company, LLC

Duke Energy owned a 24% ownership interest in Constitution, which is accounted for as an equity method investment. Constitution was a natural gas pipeline project slated to transport natural gas supplies from the Marcellus supply region in northern Pennsylvania to major northeastern markets. The pipeline was to be constructed and operated by Williams Partners L.P., which had a 41% ownership share. The remaining interest was held by Cabot Oil and Gas Corporation and WGL Holdings, Inc. In December 2014, Constitution received approval from the FERC to construct and operate the proposed pipeline. However, since April 2016, Constitution had stopped construction and discontinued capitalization of future development costs due to permitting delays and adverse rulings by regulatory agencies and courts.

In late 2019, Constitution determined that its principal shipper would not agree to an amended precedent agreement. Without such an amendment, the project would no longer be viable and, as of February 5, 2020, the Constitution partners formally resolved to initiate the dissolution of Constitution, and to terminate the Constitution Pipeline project. In the fourth quarter of 2019, Duke Energy recorded an OTTI of $25 million related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income, resulting in the full write-down of Duke Energy's investment in Constitution. See Notes 13 and 18 for additional information related to ownership interest and carrying value of the investment.

Potential Coal Plant Retirements

The Subsidiary Registrants periodically file IRPs with their state regulatory commissions. The IRPs provide a view of forecasted energy needs over a long term (10 to 20 years) and options being considered to meet those needs. IRPs filed by the Subsidiary Registrants included planning assumptions to potentially retire certain coal-fired generating facilities in North Carolina and Indiana earlier than their current estimated useful lives. Duke Energy continues to evaluate the potential need to retire these coal-fired generating facilities earlier than the current estimated useful lives and plans to seek regulatory recovery for amounts that would not be otherwise recovered when any of these assets are retired.

The table below contains the net carrying value of generating facilities planned for retirement or included in recent IRPs as evaluated for potential retirement. Dollar amounts in the table below are included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019, and exclude capitalized asset retirement costs.

	Capacity (in MW)	Remaining Net Book Value (in millions)
Duke Energy Carolinas		
Allen Steam Station Units 1-3[a]	585	$ 152
Duke Energy Indiana		
Gallagher Units 2 and 4[b]	280	114
Gibson Units 1-5[c]	3,132	1,697
Cayuga Units 1-2[c]	1,005	974
Total Duke Energy	$ 5,002	$ 2,937

(a) Duke Energy Carolinas will retire Allen Steam Station Units 1 through 3 by December 31, 2024, as part of the resolution of a lawsuit involving alleged New Source Review violations.

(b) Duke Energy Indiana committed to either retire or stop burning coal at Gallagher Units 2 and 4 by December 31, 2022, as part of the 2016 settlement of Edwardsport IGCC matters.

(c) On July 1, 2019, Duke Energy Indiana filed its 2018 IRP with the IURC. The 2018 IRP included scenarios evaluating the potential retirement of coal-fired generating units at Gibson and Cayuga. The rate case filed July 2, 2019, includes proposed depreciation rates reflecting retirement dates from 2026 to 2038.

Duke Energy continues to evaluate the potential need to retire generating facilities earlier than the current estimated useful lives, and plans to seek regulatory recovery, as necessary, for amounts that would not be otherwise recovered when any of these assets are retired. However, such recovery, including recovery of carrying costs on remaining book values, could be subject to future approvals and therefore cannot be assured.

Duke Energy Carolinas and Duke Energy Progress are evaluating the potential for coal-fired generating unit retirements with a net carrying value of approximately $721 million and $1.2 billion, respectively, included in Net property, plant and equipment on the Consolidated Balance Sheets as of December 31, 2019.

Refer to the "Western Carolinas Modernization Plan" discussion above for details of Duke Energy Progress' planned retirements.

5. COMMITMENTS AND CONTINGENCIES

INSURANCE

General Insurance

The Duke Energy Registrants have insurance and reinsurance coverage either directly or through indemnification from Duke Energy's captive insurance company, Bison, and its affiliates, consistent with companies engaged in similar commercial operations with similar type properties. The Duke Energy Registrants' coverage includes (i) commercial general liability coverage for liabilities arising to third parties for bodily injury and property damage; (ii) workers' compensation; (iii) automobile liability coverage; and (iv) property coverage for all real and personal property damage. Real and personal property damage coverage excludes electric transmission and distribution lines, but includes damages arising from boiler and machinery breakdowns, earthquakes, flood damage and extra expense, but not outage or replacement power coverage. All coverage is subject to certain deductibles or retentions, sublimits, exclusions, terms and conditions common for companies with similar types of operations. The Duke Energy Registrants self-insure their electric transmission and distribution lines against loss due to storm damage and other natural disasters. As discussed further in Note 4, Duke Energy Florida maintains a storm damage reserve and has a regulatory mechanism to recover the cost of named storms on an expedited basis.

The cost of the Duke Energy Registrants' coverage can fluctuate from year to year reflecting claims history and conditions of the insurance and reinsurance markets.

In the event of a loss, terms and amounts of insurance and reinsurance available might not be adequate to cover claims and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on the Duke Energy Registrants' results of operations, cash flows or financial position. Each company is responsible to the extent losses may be excluded or exceed limits of the coverage available.

Nuclear Insurance

Duke Energy Carolinas owns and operates McGuire and Oconee and operates and has a partial ownership interest in Catawba. McGuire and Catawba each have two reactors. Oconee has three reactors. The other joint owners of Catawba reimburse Duke Energy Carolinas for certain expenses associated with nuclear insurance per the Catawba joint owner agreements.

Duke Energy Progress owns and operates Robinson, Brunswick and Harris. Robinson and Harris each have one reactor. Brunswick has two reactors.

Duke Energy Florida owns Crystal River Unit 3, which permanently ceased operation in 2013 and reached a SAFSTOR condition in January 2018 after the successful transfer of all used nuclear fuel assemblies to an on-site dry cask storage facility.

In the event of a loss, terms and amounts of insurance available might not be adequate to cover property damage and other expenses incurred. Uninsured losses and other expenses, to the extent not recovered by other sources, could have a material effect on Duke Energy Carolinas', Duke Energy Progress' and Duke Energy Florida's results of operations, cash flows or financial position. Each company is responsible to the extent losses may be excluded or exceed limits of the coverage available.

Nuclear Liability Coverage

The Price-Anderson Act requires owners of nuclear reactors to provide for public nuclear liability protection per nuclear incident up to a maximum total financial protection liability. The maximum total financial protection liability, which is approximately $13.9 billion, is subject to change every five years for inflation and for the number of licensed reactors. Total nuclear liability coverage consists of a combination of private primary nuclear liability insurance coverage and a mandatory industry risk-sharing program to provide for excess nuclear liability coverage above the maximum reasonably available private primary coverage. The U.S. Congress could impose revenue-raising measures on the nuclear industry to pay claims.

Primary Liability Insurance

Duke Energy Carolinas and Duke Energy Progress have purchased the maximum reasonably available private primary nuclear liability insurance as required by law, which is $450 million per station. Duke Energy Florida has purchased $100 million primary nuclear liability insurance in compliance with the law.

Excess Liability Program

This program provides $13.5 billion of coverage per incident through the Price-Anderson Act's mandatory industrywide excess secondary financial protection program of risk pooling. This amount is the product of potential cumulative retrospective premium assessments of $138 million times the current 98 licensed commercial nuclear reactors in the U.S. Under this program, licensees could be assessed retrospective premiums to compensate for public nuclear liability damages in the event of a nuclear incident at any licensed facility in the U.S. Retrospective premiums may be assessed at a rate not to exceed $20.5 million per year per licensed reactor for each incident. The assessment may be subject to state premium taxes.

Nuclear Property and Accidental Outage Coverage

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are members of Nuclear Electric Insurance Limited (NEIL), an industry mutual insurance company, which provides property damage, nuclear accident decontamination and premature decommissioning insurance for each station for losses resulting from damage to its nuclear plants, either due to accidents or acts of terrorism. Additionally, NEIL provides accidental outage coverage for losses in the event of a major accidental outage at an insured nuclear station.

Pursuant to regulations of the NRC, each company's property damage insurance policies provide that all proceeds from such insurance be applied, first, to place the plant in a safe and stable condition after a qualifying accident and second, to decontaminate the plant before any proceeds can be used for decommissioning, plant repair or restoration.

Losses resulting from acts of terrorism are covered as common occurrences, such that if terrorist acts occur against one or more commercial nuclear power plants insured by NEIL within a 12-month period, they would be treated as one event and the owners of the plants where the act occurred would share one full limit of liability. The full limit of liability is currently $3.2 billion. NEIL sublimits the total aggregate for all of their policies for non-nuclear terrorist events to approximately $1.8 billion.

Each nuclear facility has accident property damage, nuclear accident decontamination and premature decommissioning liability insurance from NEIL with limits of $1.5 billion, except for Crystal River Unit 3. Crystal River Unit 3's limit is $50 million and is on an actual cash value basis. All nuclear facilities except for Catawba and Crystal River Unit 3 also share an additional $1.25 billion nuclear accident insurance limit above their dedicated underlying limit. This shared additional excess limit is not subject to reinstatement in the event of a loss. Catawba has a dedicated $1.25 billion of additional nuclear accident insurance limit above its dedicated underlying limit. Catawba and Oconee also have an additional $750 million of non-nuclear accident property damage limit. All coverages are subject to sublimits and significant deductibles.

NEIL's Accidental Outage policy provides some coverage, similar to business interruption, for losses in the event of a major accident property damage outage of a nuclear unit. Coverage is provided on a weekly limit basis after a significant waiting period deductible and at 100% of the applicable weekly limits for 52 weeks and 80% of the applicable weekly limits for up to the next 110 weeks. Coverage is provided until these applicable weekly periods are met, where the accidental outage policy limit will not exceed $490 million for McGuire and Catawba, $462 million for Brunswick and Harris, $406 million for Oconee and $364 million for Robinson. NEIL sublimits the accidental outage recovery up to the first 104 weeks of coverage not to exceed $328 million from non-nuclear accidental property damage. Coverage amounts decrease in the event more than one unit at a station is out of service due to a common accident. All coverages are subject to sublimits and significant deductibles.

Potential Retroactive Premium Assessments

In the event of NEIL losses, NEIL's board of directors may assess member companies' retroactive premiums of amounts up to 10 times their annual premiums for up to six years after a loss. NEIL has never exercised this assessment. The maximum aggregate annual retrospective premium obligations for Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are $155 million, $94 million and $1 million, respectively. Duke Energy Carolinas' maximum assessment amount includes 100% of potential obligations to NEIL for jointly owned reactors. Duke Energy Carolinas would seek reimbursement from the joint owners for their portion of these assessment amounts.

ENVIRONMENTAL

The Duke Energy Registrants are subject to federal, state and local laws regarding air and water quality, hazardous and solid waste disposal, coal ash and other environmental matters. These laws can be changed from time to time, imposing new obligations on the Duke Energy Registrants. The following environmental matters impact all of the Duke Energy Registrants.

Remediation Activities

In addition to the ARO recorded as a result of various environmental regulations, discussed in Note 10, the Duke Energy Registrants are responsible for environmental remediation at various sites. These include certain properties that are part of ongoing operations and sites formerly owned or used by Duke Energy entities. These sites are in various stages of investigation, remediation and monitoring. Managed in conjunction with relevant federal, state and local agencies, remediation activities vary based upon site conditions and location, remediation requirements, complexity and sharing of responsibility. If remediation activities involve joint and several liability provisions, strict liability, or cost recovery or contribution actions, the Duke Energy Registrants could potentially be held responsible for environmental impacts caused by other potentially responsible parties and may also benefit from insurance policies or contractual indemnities that cover some or all cleanup costs. Liabilities are recorded when losses become probable and are reasonably estimable. The total costs that may be incurred cannot be estimated because the extent of environmental impact, allocation among potentially responsible parties, remediation alternatives and/or regulatory decisions have not yet been determined at all sites. Additional costs associated with remediation activities are likely to be incurred in the future and could be significant. Costs are typically expensed as Operation, maintenance and other in the Consolidated Statements of Operations unless regulatory recovery of the costs is deemed probable.

The following tables contain information regarding reserves for probable and estimable costs related to the various environmental sites. These reserves are recorded in Accounts payable within Current Liabilities and Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Balance at December 31, 2016	$ 98	$ 10	$ 18	$ 3	$ 14	$ 59	$ 10	$ 1
Provisions/adjustments	8	3	3	2	2	3	(4)	1
Cash reductions	(25)	(3)	(6)	(2)	(4)	(15)	(1)	—
Balance at December 31, 2017	81	10	15	3	12	47	5	2
Provisions/adjustments	26	3	2	3	(2)	21	1	1
Cash reductions	(30)	(2)	(6)	(2)	(4)	(20)	(1)	(1)
Balance at December 31, 2018	77	11	11	4	6	48	5	2
Provisions/adjustments	**33**	**6**	**9**	**2**	**5**	**11**	**—**	**7**
Cash reductions	**(52)**	**(6)**	**(4)**	**(2)**	**(2)**	**(40)**	**(1)**	**(1)**
Balance at December 31, 2019	**$ 58**	**$ 11**	**$ 16**	**$ 4**	**$ 9**	**$ 19**	**$ 4**	**$ 8**

Additional losses in excess of recorded reserves that could be incurred for the stages of investigation, remediation and monitoring for environmental sites that have been evaluated at this time are not material except as presented in the table below.

(in millions)	
Duke Energy	**$ 59**
Duke Energy Carolinas	**11**
Duke Energy Ohio	**42**
Piedmont	**2**

LITIGATION

Duke Energy Carolinas and Duke Energy Progress

NCDEQ Closure Litigation

The Coal Ash Act requires CCR surface impoundments in North Carolina to be closed, with the closure method and timing based on a risk ranking classification determined by legislation or state regulators. The NCDEQ previously classified the impoundments at Allen, Belews Creek, Rogers, Marshall, Mayo and Roxboro as low risk. The Coal Ash Act allowed a range of closure options for low risk rated basins. On April 1, 2019, NCDEQ issued a closure determination (NCDEQ's April 1 Order) requiring Duke Energy Carolinas and Duke Energy Progress to excavate all remaining coal ash impoundments at these facilities. On April 26, 2019, Duke Energy Carolinas and Duke Energy Progress filed Petitions for Contested Case Hearings in the Office of Administrative Hearings to challenge NCDEQ's April 1 Order. On May 9, 2019, NCDEQ issued a supplemental order requiring that closure plans be submitted on December 31, 2019, but providing that the corrective action plans are not due until March 31, 2020. Duke Energy Carolinas and Duke Energy Progress filed amended petitions on May 24, 2019, incorporating the May 9, 2019, order.

On December 31, 2019, the parties executed a settlement agreement resolving the closure method for each of these sites. Duke Energy Carolinas and Duke Energy Progress agreed to excavate seven of the nine remaining coal ash basins at these sites with ash moved to on-site lined landfills, including two at Allen, one at Belews Creek, one at Mayo, one at Roxboro, and two at Rogers. At the two remaining basins at Marshall and Roxboro, uncapped basin ash will be excavated and moved to lined landfills. Those portions of the basins at Marshall and Roxboro, which were previously filled with ash and on which permitted facilities were constructed, will not be disturbed and will be closed pursuant to other state regulations. On February 5, 2020, the North Carolina Superior court entered a consent order, after which this litigation was dismissed on February 11, 2020.

Coal Ash Insurance Coverage Litigation

In March 2017, Duke Energy Carolinas and Duke Energy Progress filed a civil action in the North Carolina Superior Court against various insurance providers. The lawsuit seeks payment for coal ash-related liabilities covered by third-party liability insurance policies. The insurance policies were issued between 1971 and 1986 and provide third-party liability insurance for property damage. The civil action seeks damages for breach of contract and indemnification for costs arising from the Coal Ash Act and the EPA CCR rule at 15 coal-fired plants in North Carolina and South Carolina. Despite a stay of the litigation from May 2019 through September 2019 to allow the parties to discuss potential resolution, no resolution was reached, and litigation resumed. In February and March 2020, the Court will hear arguments on numerous cross motions filed by the parties to seek legal determinations concerning, among other issues, the appropriate insurance allocation methods, the trigger of the applicable coverages and several coverage defenses raised by the insurance providers. Trial is scheduled for February 2021. Duke Energy Carolinas and Duke Energy Progress cannot predict the outcome of this matter.

NCDEQ State Enforcement Actions

In the first quarter of 2013, SELC sent notices of intent to sue Duke Energy Carolinas and Duke Energy Progress related to alleged CWA violations from coal ash basins at two coal-fired power plants in North Carolina. The NCDEQ filed enforcement actions against Duke Energy Carolinas and Duke Energy Progress alleging violations of water discharge permits and North Carolina groundwater standards. The cases have been consolidated and are being heard before a single judge in the North Carolina Superior Court.

On August 16, 2013, the NCDEQ filed an enforcement action against Duke Energy Carolinas and Duke Energy Progress related to the remaining coal-fired power plants in North Carolina, alleging violations of the CWA and violations of the North Carolina groundwater standards. Both of these cases have been assigned to the judge handling the enforcement actions discussed above. SELC is representing several environmental groups who have been permitted to intervene in these cases.

The court issued orders in 2016 granting Motions for Partial Summary Judgment for seven of the 14 North Carolina plants with coal ash basins named in the enforcement actions. On February 13, 2017, the court issued an order denying motions for partial summary judgment brought by both the environmental groups and Duke Energy Carolinas and Duke Energy Progress for the remaining seven plants. On March 15, 2017, Duke Energy Carolinas and Duke Energy Progress filed a Notice of Appeal with the North Carolina Court of Appeals to challenge the trial court’s order. The parties were unable to reach an agreement at mediation in April 2017 and submitted briefs to the trial court on remaining issues to be tried. On August 1, 2018, the Court of Appeals dismissed the appeal.

Pursuant to the terms of the December 31, 2019, settlement agreement, discussed above, between Duke Energy Carolinas, Duke Energy Progress, NCDEQ and the community groups represented by the SELC, this litigation was dismissed on February 5, 2020, upon entry of the consent order in the North Carolina Superior Court.

Federal Citizens Suits

On June 13, 2016, Roanoke River Basin Association (RRBA) filed a federal citizen suit in the Middle District of North Carolina alleging unpermitted discharges to surface water and groundwater violations at the Mayo Plant. On August 19, 2016, Duke Energy Progress filed a Motion to Dismiss. On April 26, 2017, the court entered an order dismissing four of the claims in the federal citizen suit. Two claims relating to alleged violations of National Pollution Discharge Elimination System (NPDES) permit provisions survived the motion to dismiss, and Duke Energy Progress filed its response on May 10, 2017. Duke Energy Progress and RRBA each filed motions for summary judgment on March 23, 2018.

On May 16, 2017, RRBA filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina, which asserts two claims relating to alleged violations of NPDES permit provisions at the Roxboro Plant and one claim relating to the use of nearby water bodies. Duke Energy Progress and RRBA each filed motions for summary judgment on April 17, 2018.

On May 8, 2018, on motion from Duke Energy Progress, the court ordered trial in both of the above matters to be consolidated. On April 5, 2019, Duke Energy Progress filed a motion to stay the case following the NCDEQ's April 1 Order. On August 2, 2019, the court ordered that this case is stayed.

On December 5, 2017, various parties filed a federal citizen suit in the U.S. District Court for the Middle District of North Carolina for alleged violations at Duke Energy Carolinas' Belews Creek under the CWA. Duke Energy Carolinas' answer to the complaint was filed on August 27, 2018. On October 10, 2018, Duke Energy Carolinas filed Motions to Dismiss for lack of standing, Motion for Judgment on the Pleadings and Motion to Stay Discovery. On January 9, 2019, the court entered an order denying Duke Energy Carolinas' motion to stay discovery. There has been no ruling on the other pending motions. On April 5, 2019, Duke Energy Carolinas filed a motion to stay the case following the NCDEQ's April 1 Order. On August 2, 2019, the court ordered that this case is stayed.

On December 31, 2019, Duke Energy Carolinas, Duke Energy Progress, the NCDEQ and various community groups including RRBA entered into a comprehensive settlement that, among other things, resolves the method of closure at the Mayo, Roxboro and Belews Creek ash basins. On February 5, 2020, the North Carolina Superior Court entered a consent order confirming the terms of the settlement agreement, upon which RRBA filed stipulations on February 11, 2020 voluntarily dismissing all three of these federal citizen suits with prejudice.

Duke Energy Carolinas

Asbestos-related Injuries and Damages Claims

Duke Energy Carolinas has experienced numerous claims for indemnification and medical cost reimbursement related to asbestos exposure. These claims relate to damages for bodily injuries alleged to have arisen from exposure to or use of asbestos in connection with construction and maintenance activities conducted on its electric generation plants prior to 1985. As of December 31, 2019, there were 123 asserted claims for non-malignant cases with the cumulative relief sought of up to $32 million and 49 asserted claims for malignant cases with the cumulative relief sought of up to $16 million. Based on Duke Energy Carolinas' experience, it is expected that the ultimate resolution of most of these claims likely will be less than the amount claimed.

Duke Energy Carolinas has recognized asbestos-related reserves of $604 million and $630 million at December 31, 2019, and 2018, respectively. These reserves are classified in Other within Other Noncurrent Liabilities and Other within Current Liabilities on the Consolidated Balance Sheets. These reserves are based upon Duke Energy Carolinas' best estimate for current and future asbestos claims through 2039 and are recorded on an undiscounted basis. In light of the uncertainties inherent in a longer-term forecast, management does not believe they can reasonably estimate the indemnity and medical costs that might be incurred after 2039 related to such potential claims. It is possible Duke Energy Carolinas may incur asbestos liabilities in excess of the recorded reserves.

Duke Energy Carolinas has third-party insurance to cover certain losses related to asbestos-related injuries and damages above an aggregate self-insured retention. Duke Energy Carolinas' cumulative payments began to exceed the self-insurance retention in 2008. Future payments up to the policy limit will be reimbursed by the third-party insurance carrier. The insurance policy limit for potential future insurance recoveries indemnification and medical cost claim payments is $747 million in excess of the self-insured retention. Receivables for insurance recoveries were $742 million and $739 million at December 31, 2019, and 2018, respectively. These amounts are classified in Other within Other Noncurrent Assets and Receivables within Current Assets on the Consolidated Balance Sheets. Duke Energy Carolinas is not aware of any uncertainties regarding the legal sufficiency of insurance claims. Duke Energy Carolinas believes the insurance recovery asset is probable of recovery as the insurance carrier continues to have a strong financial strength rating.

Duke Energy Progress and Duke Energy Florida

Spent Nuclear Fuel Matters

On June 18, 2018, Duke Energy Progress and Duke Energy Florida sued the U.S. in the U.S. Court of Federal Claims for damages incurred for the period 2014 through 2018. The lawsuit claimed the Department of Energy breached a contract in failing to accept spent nuclear fuel under the Nuclear Waste Policy Act of 1982 and asserted damages for the cost of on-site storage in the amount of $100 million and $203 million for Duke Energy Progress and Duke Energy Florida, respectively. Discovery is ongoing and a trial is expected to occur in early 2021.

Duke Energy Florida

Fluor Contract Litigation

On January 29, 2019, Fluor filed a breach of contract lawsuit in the U.S. District Court for the Middle District of Florida against Duke Energy Florida related to an EPC agreement for the CC natural gas plant in Citrus County, Florida. Fluor filed an amended complaint on February 13, 2019. Fluor's multicount complaint seeks civil, statutory and contractual remedies related to Duke Energy Florida's $67 million draw in early 2019, on Fluor's letter of credit and offset of invoiced amounts. Duke Energy Florida moved to dismiss all counts of Fluor's amended complaint, and on April 16, 2019, the court dismissed Fluor's complaint without prejudice. On April 26, 2019, Fluor filed a second amended complaint.

On August 1, 2019, Duke Energy Florida and Fluor reached a settlement to resolve the pending litigation and other outstanding issues related to completing the Citrus County CC. Pursuant to the terms of the settlement, Fluor filed a notice of voluntary dismissal, and on August 27, 2019, the court dismissed the case with prejudice. As a result of the settlement with Fluor, Duke Energy Florida recorded a $36 million reduction to a prior-year impairment within Impairment charges on Duke Energy's Consolidated Statements of Operations in 2019.

Other Litigation and Legal Proceedings

The Duke Energy Registrants are involved in other legal, tax and regulatory proceedings arising in the ordinary course of business, some of which involve significant amounts. The Duke Energy Registrants believe the final disposition of these proceedings will not have a material effect on their results of operations, cash flows or financial position.

The table below presents recorded reserves based on management's best estimate of probable loss for legal matters, excluding asbestos-related reserves. Reserves are classified on the Consolidated Balance Sheets in Other within Other Noncurrent Liabilities and Other within Current Liabilities. The reasonably possible range of loss in excess of recorded reserves is not material, other than as described above.

	December 31,	
(in millions)	**2019**	**2018**
Reserves for Legal Matters		
Duke Energy	**$ 62**	$ 65
Duke Energy Carolinas	**2**	9
Progress Energy	**55**	54
Duke Energy Progress	**12**	12
Duke Energy Florida	**22**	24
Piedmont	**1**	1

OTHER COMMITMENTS AND CONTINGENCIES

General

As part of their normal business, the Duke Energy Registrants are party to various financial guarantees, performance guarantees and other contractual commitments to extend guarantees of credit and other assistance to various subsidiaries, investees and other third parties. These guarantees involve elements of performance and credit risk, which are not fully recognized on the Consolidated Balance Sheets and have uncapped maximum potential payments. See Note 8 for more information.

Purchase Obligations

Purchased Power

Duke Energy Progress, Duke Energy Florida and Duke Energy Ohio have ongoing purchased power contracts, including renewable energy contracts, with other utilities, wholesale marketers, co-generators and qualified facilities. These purchased power contracts generally provide for capacity and energy payments. In addition, Duke Energy Progress and Duke Energy Florida have various contracts to secure transmission rights.

The following table presents executory purchased power contracts with terms exceeding one year, excluding contracts classified as leases.

		Minimum Purchase Amount at December 31, 2019						
(in millions)	**Contract Expiration**	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Duke Energy Progress[a]	2021-2032	$ 46	$ 66	$ 63	$ 55	$ 56	$ 123	$ 409
Duke Energy Florida[b]	2021-2025	374	356	354	374	262	91	1,811
Duke Energy Ohio[c][d]	2021-2022	132	107	32	—	—	—	271

(a) Contracts represent either 100% of net plant output or vary.
(b) Contracts represent between 81% and 100% of net plant output.
(c) Contracts represent between 1% and 9% of net plant output.
(d) Excludes PPA with OVEC. See Note 18 for additional information.

Gas Supply and Capacity Contracts

Duke Energy Ohio and Piedmont routinely enter into long-term natural gas supply commodity and capacity commitments and other agreements that commit future cash flows to acquire services needed in their businesses. These commitments include pipeline and storage capacity contracts and natural gas supply contracts to provide service to customers. Costs arising from the natural gas supply commodity and capacity commitments, while significant, are pass-through costs to customers and are generally fully recoverable through the fuel adjustment or PGA procedures and prudence reviews in North Carolina and South Carolina and under the Tennessee Incentive Plan in Tennessee. In the Midwest, these costs are recovered via the Gas Cost Recovery Rate in Ohio or the Gas Cost Adjustment Clause in Kentucky. The time periods for fixed payments under pipeline and storage capacity contracts are up to 15 years. The time periods for fixed payments under natural gas supply contracts are up to six years. The time period for the natural gas supply purchase commitments is up to 11 years.

Certain storage and pipeline capacity contracts require the payment of demand charges that are based on rates approved by the FERC in order to maintain rights to access the natural gas storage or pipeline capacity on a firm basis during the contract term. The demand charges that are incurred in each period are recognized in the Consolidated Statements of Operations and Comprehensive Income as part of natural gas purchases and are included in Cost of natural gas.

The following table presents future unconditional purchase obligations under natural gas supply and capacity contracts as of December 31, 2019.

(in millions)	Duke Energy	Duke Energy Ohio	Piedmont
2020	$ 297	$ 39	$ 258
2021	280	33	247
2022	225	14	211
2023	129	3	126
2024	118	—	118
Thereafter	714	—	714
Total	$ 1,763	$ 89	$ 1,674

6. LEASES

As described in Note 1, Duke Energy adopted the revised accounting guidance for Leases effective January 1, 2019, using the modified retrospective method of adoption, which does not require restatement of prior year reported results. Adoption of the new standard resulted in the recording of ROU assets and operating lease liabilities as follows:

	As of January 1, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
ROU assets	$ 1,750	$ 153	$ 863	$ 407	$ 456	$ 23	$ 61	$ 26
Operating lease liabilities – current	205	28	96	35	61	1	4	4
Operating lease liabilities – noncurrent	1,504	127	766	371	395	22	58	25

As part of its operations, Duke Energy leases certain aircraft, space on communication towers, industrial equipment, fleet vehicles, fuel transportation (barges and railcars), land and office space under various terms and expiration dates. Additionally, Duke Energy Carolinas, Duke Energy Progress and Duke Energy Indiana have finance leases related to firm natural gas pipeline transportation capacity. Duke Energy Progress and Duke Energy Florida have entered into certain PPAs, which are classified as finance and operating leases.

Duke Energy has certain lease agreements, which include variable lease payments that are based on the usage of an asset. These variable lease payments are not included in the measurement of the ROU assets or operating lease liabilities on the Consolidated Financial Statements.

Certain Duke Energy lease agreements include options for renewal and early termination. The intent to renew a lease varies depending on the lease type and asset. Renewal options that are reasonably certain to be exercised are included in the lease measurements. The decision to terminate a lease early is dependent on various economic factors. No termination options have been included in any of the lease measurements.

Duke Energy Carolinas entered into a sale-leaseback arrangement in December 2019, to construct and occupy an office tower. The lease agreement was evaluated as a sale-leaseback of real estate and it was determined that the transaction did not qualify for sale-leaseback accounting. As a result, the transaction is being accounted for as a financing. For this transaction, Duke Energy Carolinas will continue to record the real estate on the Consolidated Balance Sheets within Property, Plant and Equipment as if it were the legal owner and will continue to recognize depreciation expense over the estimated useful life. In addition, a liability will be recorded for the failed sale-leaseback obligation within Long-Term Debt on the Consolidated Balance Sheets, with the monthly lease payments commencing after the construction phase being split between interest expense and principal pay down of the debt.

Duke Energy operates various renewable energy projects and sells the generated output to utilities, electric cooperatives, municipalities and commercial and industrial customers through long-term PPAs. In certain situations, these PPAs and the associated renewable energy projects qualify as operating leases. Rental income from these leases is accounted for as Nonregulated electric and other revenues in the Consolidated Statements of Operations. There are no minimum lease payments as all payments are contingent based on actual electricity generated by the renewable energy projects. Contingent lease payments were $264 million, $268 million and $262 million for the years ended December 31, 2019, 2018, and 2017, respectively. Renewable energy projects owned by Duke Energy and accounted for as operating leases had a cost basis of $3,349 million and $3,358 million and accumulated depreciation of $721 million and $602 million at December 31, 2019, and 2018, respectively. These assets are principally classified as nonregulated electric generation and transmission assets.

Piedmont has an agreement with Duke Energy Carolinas for the construction and transportation of natural gas pipelines to supply its natural gas plant needs. Piedmont accounts for this pipeline lateral contract as a lessor and sales-type lease since the present value of the sum of the lease payments equals the fair value of the asset. As of December 31, 2019, the pipeline lateral assets owned by Piedmont had a current net investment basis of $4 million and a long-term net investment basis of $70 million. These assets are classified in Other, within Current Assets and Other Noncurrent Assets, respectively, on Piedmont's Consolidated Balance Sheets. Duke Energy Carolinas accounts for the contract as a finance lease. The activity for this contract is eliminated in consolidation at Duke Energy.

The following table presents the components of lease expense.

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Operating lease expense[a]	$ 292	$ 47	$ 161	$ 69	$ 92	$ 11	$ 20	$ 5
Short-term lease expense[a]	16	5	9	4	5	1	2	—
Variable lease expense[a]	47	22	22	16	6	—	1	1
Finance lease expense								
Amortization of leased assets[b]	111	6	21	5	16	1	—	—
Interest on lease liabilities[c]	61	15	42	33	9	—	1	—
Total finance lease expense	172	21	63	38	25	1	1	—
Total lease expense	$ 527	$ 95	$ 255	$ 127	$ 128	$ 13	$ 24	$ 6

(a) Included in Operations, maintenance and other or, for barges and railcars, Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.
(b) Included in Depreciation and amortization on the Consolidated Statements of Operations.
(c) Included in Interest Expense on the Consolidated Statements of Operations.

The following table presents rental expense for operating leases, as reported under the former lease standard. These amounts are included in Operation, maintenance and other and Fuel used in electric generation and purchased power on the Consolidated Statements of Operations.

	Years Ended December 31,	
(in millions)	**2018**	**2017**
Duke Energy	$ 268	$ 241
Duke Energy Carolinas	49	44
Progress Energy	143	130
Duke Energy Progress	75	75
Duke Energy Florida	68	55
Duke Energy Ohio	13	15
Duke Energy Indiana	21	23
Piedmont	11	7

The following table presents operating lease maturities and a reconciliation of the undiscounted cash flows to operating lease liabilities.

	December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
2020	**$ 268**	**$ 31**	**$ 123**	**$ 51**	**$ 72**	**$ 2**	**$ 5**	**$ 5**
2021	**216**	**19**	**99**	**44**	**55**	**2**	**4**	**5**
2022	**201**	**19**	**95**	**40**	**55**	**2**	**4**	**5**
2023	**191**	**17**	**95**	**41**	**54**	**2**	**4**	**5**
2024	**176**	**13**	**95**	**41**	**54**	**2**	**4**	**5**
Thereafter	**984**	**57**	**462**	**283**	**179**	**21**	**64**	**5**
Total operating lease payments	**2,036**	**156**	**969**	**500**	**469**	**31**	**85**	**30**
Less: present value discount	**(396)**	**(27)**	**(177)**	**(109)**	**(68)**	**(9)**	**(27)**	**(3)**
Total operating lease liabilities[a]	**$ 1,640**	**$ 129**	**$ 792**	**$ 391**	**$ 401**	**$ 22**	**$ 58**	**$ 27**

(a) Certain operating lease payments include renewal options that are reasonably certain to be exercised.

The following table presents future minimum lease payments under operating leases, which at inception had a noncancelable term of more than one year, as reported under the former lease standard.

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2019	$ 239	$ 33	$ 97	$ 49	$ 48	$ 2	$ 6	$ 5
2020	219	29	90	46	44	2	5	5
2021	186	19	79	37	42	2	4	5
2022	170	19	76	34	42	2	4	5
2023	160	17	77	35	42	2	5	6
Thereafter	1,017	68	455	314	141	23	66	11
Total	$ 1,991	$ 185	$ 874	$ 515	$ 359	$ 33	$ 90	$ 37

The following table presents finance lease maturities and a reconciliation of the undiscounted cash flows to finance lease liabilities.

	December 31, 2019					
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Indiana
2020	$ 181	$ 28	$ 69	$ 44	$ 25	$ 1
2021	186	23	69	44	25	1
2022	173	23	69	44	25	1
2023	175	23	69	44	25	1
2024	121	23	55	44	11	1
Thereafter	823	314	539	528	11	27
Total finance lease payments	1,659	434	870	748	122	32
Less: amounts representing interest	(690)	(255)	(465)	(441)	(24)	(22)
Total finance lease liabilities	$ 969	$ 179	$ 405	$ 307	$ 98	$ 10

The following table presents future minimum lease payments under finance leases, as reported under the former lease standard.

	December 31, 2018						
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
2019	$ 170	$ 20	$ 45	$ 20	$ 25	$ 2	$ 1
2020	174	20	46	21	25	—	1
2021	177	15	45	20	25	—	1
2022	165	15	45	21	24	—	1
2023	165	15	45	21	24	—	1
Thereafter	577	204	230	209	21	—	27
Minimum annual payments	1,428	289	456	312	144	2	32
Less: amount representing interest	(487)	(180)	(205)	(175)	(30)	—	(22)
Total	$ 941	$ 109	$ 251	$ 137	$ 114	$ 2	$ 10

The following tables contain additional information related to leases.

		December 31, 2019							
(in millions)	Classification	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Assets									
Operating	Operating lease ROU assets, net	$ 1,658	$ 123	$ 788	$ 387	$ 401	$ 21	$ 57	$ 24
Finance	Net property, plant and equipment	926	198	443	308	135	—	7	—
Total lease assets		$ 2,584	$ 321	$ 1,231	$ 695	$ 536	$ 21	$ 64	$ 24
Liabilities									
Current									
Operating	Other current liabilities	$ 208	$ 27	$ 95	$ 37	$ 58	$ 1	$ 3	$ 4
Finance	Current maturities of long-term debt	119	7	24	6	18	—	—	—
Noncurrent									
Operating	Operating lease liabilities	1,432	102	697	354	343	21	55	23
Finance	Long-Term Debt	850	172	381	301	80	—	10	—
Total lease liabilities		$ 2,609	$ 308	$ 1,197	$ 698	$ 499	$ 22	$ 68	$ 27

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Cash paid for amounts included in the measurement of lease liabilities[a]								
Operating cash flows from operating leases	$ 285	$ 34	$ 131	$ 53	$ 78	$ 2	$ 7	$ 7
Operating cash flows from finance leases	61	15	42	33	9	—	1	—
Financing cash flows from finance leases	111	6	21	5	16	1	—	—
Lease assets obtained in exchange for new lease liabilities (non-cash)								
Operating[b]	$ 194	$ 44	$ 30	$ 30	$ —	$ —	$ —	$ 1
Finance	251	76	175	175	—	—	—	—

(a) No amounts were classified as investing cash flows from operating leases for the year ended December 31, 2019.
(b) Does not include ROU assets recorded as a result of the adoption of the new lease standard.

	December 31, 2019							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Weighted average remaining lease term (years)								
Operating leases	11	9	10	12	8	17	18	6
Finance leases	13	19	16	18	11	—	26	—
Weighted average discount rate[a]								
Operating leases	3.9%	3.5%	3.8%	3.9%	3.8%	4.2%	4.1%	3.6%
Finance leases	8.1%	11.8%	11.9%	12.4%	8.3%	—%	11.9%	—%

(a) The discount rate is calculated using the rate implicit in a lease if it is readily determinable. Generally, the rate used by the lessor is not provided to Duke Energy and in these cases the incremental borrowing rate is used. Duke Energy will typically use its fully collateralized incremental borrowing rate as of the commencement date to calculate and record the lease. The incremental borrowing rate is influenced by the lessee's credit rating and lease term and as such may differ for individual leases, embedded leases or portfolios of leased assets.

7. DEBT AND CREDIT FACILITIES

Summary of Debt and Related Terms

The following tables summarize outstanding debt.

	December 31, 2019								
(in millions)	Weighted Average Interest Rate	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured debt, maturing 2020-2078	4.02%	$ 22,477	$ 1,150	$ 3,650	$ 700	$ 350	$ 1,110	$ 405	$ 2,399
Secured debt, maturing 2020-2052	3.30%	4,537	544	1,722	335	1,387	—	—	—
First mortgage bonds, maturing 2020-2049[a]	4.13%	27,977	9,557	13,800	7,575	6,225	1,449	3,169	—
Finance leases, maturing 2022-2051[b]	6.60%	969	179	405	307	98	—	10	—
Tax-exempt bonds, maturing 2022-2041[c]	2.90%	730	243	48	48	—	77	362	—
Notes payable and commercial paper[d]	1.98%	3,588	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	329	1,970	216	—	337	180	476
Fair value hedge carrying value adjustment		5	5	—	—	—	—	—	—
Unamortized debt discount and premium, net[e]		1,294	(23)	(29)	(17)	(11)	(30)	(19)	(2)
Unamortized debt issuance costs[f]		(316)	(55)	(111)	(40)	(62)	(12)	(20)	(13)
Total debt	3.92%	$ 61,261	$ 11,929	$ 21,455	$ 9,124	$ 7,987	$ 2,931	$ 4,087	$ 2,860
Short-term notes payable and commercial paper		(3,135)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(29)	(1,821)	(66)	—	(312)	(30)	(476)
Current maturities of long-term debt[g]		(3,141)	(458)	(1,577)	(1,006)	(571)	—	(503)	—
Total long-term debt[g]		$ 54,985	$ 11,442	$ 18,057	$ 8,052	$ 7,416	$ 2,619	$ 3,554	$ 2,384

Substantially all electric utility property is mortgaged under mortgage bond indentures.

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.

(b) Duke Energy includes $44 million and $419 million of finance lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to PPAs that are not accounted for as finance leases in their respective financial statements because of grandfathering provisions in GAAP.

(c) Substantially all tax-exempt bonds are secured by first mortgage bonds, letters of credit or the Master Credit Facility.

(d) Includes $625 million classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy's commercial paper program was 14 days.

(e) Duke Energy includes $1,275 million and $137 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $37 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 18 for additional information on amounts from consolidated VIEs.

	December 31, 2018								
(in millions)	Weighted Average Interest Rate	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured debt, maturing 2019-2078	4.26%	$ 20,955	$ 1,150	$ 3,800	$ 50	$ 350	$ 1,000	$ 408	$ 2,150
Secured debt, maturing 2020-2037	3.69%	4,297	450	1,703	300	1,403	—	—	—
First mortgage bonds, maturing 2019-2048(a)	4.32%	25,628	8,759	13,100	7,574	5,526	1,099	2,670	—
Finance leases, maturing 2019-2051(b)	5.06%	941	109	251	137	114	2	10	—
Tax-exempt bonds, maturing 2019-2041(c)	3.40%	941	243	48	48	—	77	572	—
Notes payable and commercial paper(d)	2.73%	4,035	—	—	—	—	—	—	—
Money pool/intercompany borrowings		—	739	1,385	444	108	299	317	198
Fair value hedge carrying value adjustment		5	5	—	—	—	—	—	—
Unamortized debt discount and premium, net(e)		1,434	(23)	(29)	(15)	(11)	(31)	(8)	(1)
Unamortized debt issuance costs(f)		(297)	(54)	(112)	(40)	(61)	(7)	(20)	(11)
Total debt	4.13%	$ 57,939	$ 11,378	$ 20,146	$ 8,498	$ 7,429	$ 2,439	$ 3,949	$ 2,336
Short-term notes payable and commercial paper		(3,410)	—	—	—	—	—	—	—
Short-term money pool/intercompany borrowings		—	(439)	(1,235)	(294)	(108)	(274)	(167)	(198)
Current maturities of long-term debt(g)		(3,406)	(6)	(1,672)	(603)	(270)	(551)	(63)	(350)
Total long-term debt(g)		$ 51,123	$ 10,933	$ 17,239	$ 7,601	$ 7,051	$ 1,614	$ 3,719	$ 1,788

(a) Substantially all electric utility property is mortgaged under mortgage bond indentures.
(b) Duke Energy includes $63 million and $531 million of finance lease purchase accounting adjustments related to Duke Energy Progress and Duke Energy Florida, respectively, related to PPAs that are not accounted for as finance leases in their respective financial statements because of grandfathering provisions in GAAP.
(c) Substantially all tax-exempt bonds are secured by first mortgage bonds, letters of credit or the Master Credit Facility.
(d) Includes $625 million that was classified as Long-Term Debt on the Consolidated Balance Sheets due to the existence of long-term credit facilities that backstop these commercial paper balances, along with Duke Energy's ability and intent to refinance these balances on a long-term basis. The weighted average days to maturity for Duke Energy's commercial paper programs was 16 days.
(e) Duke Energy includes $1,380 million and $156 million in purchase accounting adjustments related to Progress Energy and Piedmont, respectively.
(f) Duke Energy includes $41 million in purchase accounting adjustments primarily related to the merger with Progress Energy.
(g) Refer to Note 18 for additional information on amounts from consolidated VIEs.

Current Maturities of Long-Term Debt

The following table shows the significant components of Current maturities of Long-Term Debt on the Consolidated Balance Sheets. The Duke Energy Registrants currently anticipate satisfying these obligations with cash on hand and proceeds from additional borrowings.

(in millions)	Maturity Date	Interest Rate	December 31, 2019
Unsecured Debt			
Duke Energy (Parent)	June 2020	2.100%	$ 330
Duke Energy Progress	December 2020	2.510% (a)	700
First Mortgage Bonds			
Duke Energy Florida	January 2020	1.850%	250
Duke Energy Florida	April 2020	4.550%	250
Duke Energy Carolinas	June 2020	4.300%	450
Duke Energy Indiana	July 2020	3.750%	500
Duke Energy Progress	September 2020	2.065% (a)	300
Other[b]			361
Current maturities of long-term debt			$ 3,141

(a) Debt has a floating interest rate.
(b) Includes finance lease obligations, amortizing debt and small bullet maturities.

Maturities and Call Options

The following table shows the annual maturities of long-term debt for the next five years and thereafter. Amounts presented exclude short-term notes payable, commercial paper and money pool borrowings and debt issuance costs for the Subsidiary Registrants.

	December 31, 2019							
(in millions)	Duke Energy[a]	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
2020	$ 3,141	$ 458	$ 1,578	$ 1,006	$ 572	—	$ 503	$ —
2021	5,053	504	2,257	932	825	50	70	160
2022	4,334	830	1,048	508	90	—	94	—
2023	3,112	1,006	398	319	79	325	3	45
2024	1,965	306	227	160	67	25	154	40
Thereafter	39,542	8,875	14,267	6,190	6,427	2,261	3,272	2,155
Total long-term debt, including current maturities	$ 57,147	$ 11,979	$ 19,775	$ 9,115	$ 8,060	$ 2,661	$ 4,096	$ 2,400

(a) Excludes $1,448 million in purchase accounting adjustments related to the Progress Energy merger and the Piedmont acquisition.

The Duke Energy Registrants have the ability under certain debt facilities to call and repay the obligation prior to its scheduled maturity. Therefore, the actual timing of future cash repayments could be materially different than as presented above.

Short-Term Obligations Classified as Long-Term Debt

Tax-exempt bonds that may be put to the Duke Energy Registrants at the option of the holder and certain commercial paper issuances and money pool borrowings are classified as Long-Term Debt on the Consolidated Balance Sheets. These tax-exempt bonds, commercial paper issuances and money pool borrowings, which are short-term obligations by nature, are classified as long-term due to Duke Energy's intent and ability to utilize such borrowings as long-term financing. As Duke Energy's Master Credit Facility and other bilateral letter of credit agreements have non-cancelable terms in excess of one year as of the balance sheet date, Duke Energy has the ability to refinance these short-term obligations on a long-term basis. The following tables show short-term obligations classified as long-term debt.

	December 31, 2019				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Ohio**	**Duke Energy Indiana**
Tax-exempt bonds	**$ 312**	**$ —**	**$ —**	**$ 27**	**$ 285**
Commercial paper[a]	**625**	**300**	**150**	**25**	**150**
Total	**$ 937**	**$ 300**	**$ 150**	**$ 52**	**$ 435**

	December 31, 2018				
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Duke Energy Progress**	**Duke Energy Ohio**	**Duke Energy Indiana**
Tax-exempt bonds	$ 312	$ —	$ —	$ 27	$ 285
Commercial paper[a]	625	300	150	25	150
Total	$ 937	$ 300	$ 150	$ 52	$ 435

(a) Progress Energy amounts are equal to Duke Energy Progress amounts.

Summary of Significant Debt Issuances

The following tables summarize significant debt issuances (in millions).

			Year Ended December 31, 2019							
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unsecured Debt										
March 2019[a]	Mar 2022	(b)	$ 300	$ 300	$ —	$ —	$ —	$ —	$ —	$ —
March 2019[a]	Mar 2022	3.227%	300	300	—	—	—	—	—	—
May 2019[e]	Jun 2029	3.500%	600	—	—	—	—	—	—	600
June 2019[a]	Jun 2029	3.400%	600	600	—	—	—	—	—	—
June 2019[a]	Jun 2049	4.200%	600	600	—	—	—	—	—	—
July 2019[g]	Jul 2049	4.320%	40	—	—	—	—	40	—	—
September 2019[g]	Oct 2025	3.230%	95	—	—	—	—	95	—	—
September 2019[g]	Oct 2029	3.560%	75	—	—	—	—	75	—	—
November 2019[h]	Nov 2021	(b) 2.167%	200	—	—	—	200	—	—	—
First Mortgage Bonds										
January 2019[c]	Feb 2029	3.650%	400	—	—	—	—	400	—	—
January 2019[c]	Feb 2049	4.300%	400	—	—	—	—	400	—	—
March 2019[d]	Mar 2029	3.450%	600	—	—	600	—	—	—	—
August 2019[a]	Aug 2029	2.450%	450	—	450	—	—	—	—	—
August 2019[a]	Aug 2049	3.200%	350	—	350	—	—	—	—	—
September 2019[f]	Oct 2049	3.250%	500	—	—	—	—	—	500	—
November 2019[i]	Dec 2029	2.500%	700	—	—	—	700	—	—	—
Total issuances			$ 6,210	$ 1,800	$ 800	$ 600	$ 900	$ 1,010	$ 500	$ 600

(a) Debt issued to pay down short-term debt and for general corporate purposes.
(b) Debt issuance has a floating interest rate.
(c) Debt issued to repay at maturity $450 million first mortgage bonds due April 2019, pay down short-term debt and for general corporate purposes.
(d) Debt issued to fund eligible green energy projects in the Carolinas.
(e) Debt issued to repay in full the outstanding $350 million Piedmont unsecured term loan due September 2019, pay down short-term debt and for general corporate purposes.
(f) Debt issued to retire $150 million of pollution control bonds, pay down short-term debt and for general corporate purposes.
(g) Debt issued to repay at maturity $100 million debentures due October 2019, pay down short-term debt and for general corporate purposes.
(h) Debt issued to fund storm restoration costs and for general corporate purposes.
(i) Debt issued to reimburse the payment of existing and new Eligible Green Expenditures in Florida.

In January 2020, Duke Energy Carolinas closed and funded $900 million of first mortgage bonds of which $500 million carry a fixed interest rate of 2.45% and mature February 2030 and $400 million carry a fixed interest rate of 3.20% and mature August 2049. The proceeds will be used to repay at maturity $450 million, 4.30% debentures maturing June 2020, and for general corporate purposes.

			Year Ended December 31, 2018				
Issuance Date	Maturity Date	Interest Rate	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
Unsecured Debt							
March 2018[a]	April 2025	3.950%	$ 250	$ 250	$ —	$ —	$ —
May 2018[b]	May 2021	3.114%	500	500	—	—	—
September 2018[c]	September 2078	5.625%	500	500	—	—	—
First Mortgage Bonds							
March 2018[d]	March 2023	3.050%	500	—	500	—	—
March 2018[d]	March 2048	3.950%	500	—	500	—	—
June 2018[e]	July 2028	3.800%	600	—	—	—	600
June 2018[e]	July 2048	4.200%	400	—	—	—	400
August 2018[f]	September 2023	3.375%	300	—	—	300	—
August 2018[f]	September 2028	3.700%	500	—	—	500	—
November 2018[g]	May 2022	3.350%	350	—	350	—	—
November 2018[g]	November 2028	3.950%	650	—	650	—	—
Total issuances			$ 5,050	$ 1,250	$ 2,000	$ 800	$ 1,000

(a) Debt issued to pay down short-term debt.
(b) Debt issued to pay down short-term debt. Debt issuance has a floating debt rate.
(c) Callable after September 2023 at par. Junior subordinated hybrid debt issued to pay down short-term debt and for general corporate purposes.
(d) Debt issued to repay at maturity a $300 million first mortgage bond due April 2018, pay down intercompany short-term debt and for general corporate purposes.
(e) Debt issued to repay a portion of intercompany short-term debt under the money pool borrowing arrangement and for general corporate purposes.
(f) Debt issued to repay short-term debt and for general corporate purposes.
(g) Debt issued to fund eligible green energy projects, including zero-carbon solar and energy storage, in the Carolinas.

Available Credit Facilities

In March 2019, Duke Energy amended its existing $8 billion Master Credit Facility to extend the termination date to March 2024. The Duke Energy Registrants, excluding Progress Energy, have borrowing capacity under the Master Credit Facility up to a specified sublimit for each borrower. Duke Energy has the unilateral ability at any time to increase or decrease the borrowing sublimits of each borrower, subject to a maximum sublimit for each borrower. The amount available under the Master Credit Facility has been reduced to backstop issuances of commercial paper, certain letters of credit and variable-rate demand tax-exempt bonds that may be put to the Duke Energy Registrants at the option of the holder. Duke Energy Carolinas and Duke Energy Progress are also required to each maintain $250 million of available capacity under the Master Credit Facility as security to meet obligations under plea agreements reached with the U.S. Department of Justice in 2015 related to violations at North Carolina facilities with ash basins.

The table below includes the current borrowing sublimits and available capacity under these credit facilities.

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy (Parent)	Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Facility size[a]	$ 8,000	$ 2,650	$ 1,500	$ 1,250	$ 800	$ 600	$ 600	$ 600
Reduction to backstop issuances								
Commercial paper[b]	(2,537)	(1,119)	(325)	(207)	—	(296)	(176)	(414)
Outstanding letters of credit	(50)	(42)	(4)	(2)	—	—	—	(2)
Tax-exempt bonds	(81)	—	—	—	—	—	(81)	—
Coal ash set-aside	(500)	—	(250)	(250)	—	—	—	—
Available capacity	$ 4,832	$ 1,489	$ 921	$ 791	$ 800	$ 304	$ 343	$ 184

(a) Represents the sublimit of each borrower.

(b) Duke Energy issued $625 million of commercial paper and loaned the proceeds through the money pool to Duke Energy Carolinas, Duke Energy Progress, Duke Energy Ohio and Duke Energy Indiana. The balances are classified as Long-Term Debt Payable to Affiliated Companies in the Consolidated Balance Sheets.

Three-Year Revolving Credit Facility

Duke Energy (Parent) has a $1 billion revolving credit facility. The facility had an initial termination date of June 2020, but in May 2019, Duke Energy extended the termination date of the facility to May 2022. Borrowings under this facility will be used for general corporate purposes. As of December 31, 2019, $500 million has been drawn under this facility. This balance is classified as Long-term debt on Duke Energy's Consolidated Balance Sheets. Any undrawn commitments can be drawn, and borrowings can be prepaid, at any time throughout the term of the facility. The terms and conditions of the facility are generally consistent with those governing Duke Energy's Master Credit Facility.

Duke Energy Progress Term Loan Facility

In December 2018, Duke Energy Progress entered into a two-year term loan facility with commitments totaling $700 million. Borrowings under the facility were used to pay storm-related costs, pay down commercial paper and to partially finance an upcoming bond maturity. As of December 31, 2019, the entire $700 million has been drawn under the term loan. This balance is classified as Current maturities of long-term debt on Duke Energy Progress' Consolidated Balance Sheets.

Piedmont Term Loan Facility

In May 2019, the $350 million Piedmont term loan was paid off in full with proceeds from the $600 million Piedmont debt offering.

Other Debt Matters

In September 2019, Duke Energy filed a Form S-3 with the SEC. Under this Form S-3, which is uncapped, the Duke Energy Registrants, excluding Progress Energy, may issue debt and other securities in the future at amounts, prices and with terms to be determined at the time of future offerings. The registration statement was filed to replace a similar prior filing upon expiration of its three-year term and also allows for the issuance of common and preferred stock by Duke Energy. The expired Form S-3 was amended in March 2019, to allow Duke Energy to issue preferred stock.

Duke Energy has an effective Form S-3 with the SEC to sell up to $3 billion of variable denomination floating-rate demand notes, called PremierNotes. The Form S-3 states that no more than $1.5 billion of the notes will be outstanding at any particular time. The notes are offered on a continuous basis and bear interest at a floating rate per annum determined by the Duke Energy PremierNotes Committee, or its designee, on a weekly basis. The interest rate payable on notes held by an investor may vary based on the principal amount of the investment. The notes have no stated maturity date, are non-transferable and may be redeemed in whole or in part by Duke Energy or at the investor's option at any time. The balance as of December 31, 2019, and 2018, was $1,049 million and $1,010 million, respectively. The notes are short-term debt obligations of Duke Energy and are reflected as Notes payable and commercial paper on Duke Energy's Consolidated Balance Sheets.

Money Pool

The Subsidiary Registrants, excluding Progress Energy, are eligible to receive support for their short-term borrowing needs through participation with Duke Energy and certain of its subsidiaries in a money pool arrangement. Under this arrangement, those companies with short-term funds may provide short-term loans to affiliates participating in this arrangement. The money pool is structured such that the Subsidiary Registrants, excluding Progress Energy, separately manage their cash needs and working capital requirements. Accordingly, there is no net settlement of receivables and payables between money pool participants. Duke Energy (Parent), may loan funds to its participating subsidiaries, but may not borrow funds through the money pool. Accordingly, as the money pool activity is between Duke Energy and its wholly owned subsidiaries, all money pool balances are eliminated within Duke Energy's Consolidated Balance Sheets.

Money pool receivable balances are reflected within Notes receivable from affiliated companies on the Subsidiary Registrants' Consolidated Balance Sheets. Money pool payable balances are reflected within either Notes payable to affiliated companies or Long-Term Debt Payable to Affiliated Companies on the Subsidiary Registrants' Consolidated Balance Sheets.

Restrictive Debt Covenants

The Duke Energy Registrants' debt and credit agreements contain various financial and other covenants. Duke Energy's Master Credit Facility contains a covenant requiring the debt-to-total capitalization ratio not to exceed 65% for each borrower, excluding Piedmont, and 70% for Piedmont. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreements. As of December 31, 2019, each of the Duke Energy Registrants was in compliance with all covenants related to their debt agreements. In addition, some credit agreements may allow for acceleration of payments or termination of the agreements due to nonpayment, or acceleration of other significant indebtedness of the borrower or some of its subsidiaries. None of the debt or credit agreements contain material adverse change clauses.

Other Loans

As of December 31, 2019, and 2018, Duke Energy had loans outstanding of $777 million, including $36 million at Duke Energy Progress and $741 million, including $37 million at Duke Energy Progress, respectively, against the cash surrender value of life insurance policies it owns on the lives of its executives. The amounts outstanding were carried as a reduction of the related cash surrender value that is included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets.

8. GUARANTEES AND INDEMNIFICATIONS

Duke Energy has various financial and performance guarantees and indemnifications with non-consolidated entities, which are issued in the normal course of business. As discussed below, these contracts include performance guarantees, standby letters of credit, debt guarantees and indemnifications. Duke Energy enters into these arrangements to facilitate commercial transactions with third parties by enhancing the value of the transaction to the third party. At December 31, 2019, Duke Energy does not believe conditions are likely for significant performance under these guarantees. To the extent liabilities are incurred as a result of the activities covered by the guarantees, such liabilities are included on the accompanying Consolidated Balance Sheets.

On January 2, 2007, Duke Energy completed the spin-off of its previously wholly-owned natural gas businesses to shareholders. Guarantees issued by Duke Energy or its affiliates, or assigned to Duke Energy prior to the spin-off, remained with Duke Energy subsequent to the spin-off. Guarantees issued by Spectra Capital or its affiliates prior to the spin-off remained with Spectra Capital subsequent to the spin-off, except for guarantees that were later assigned to Duke Energy. Duke Energy has indemnified Spectra Capital against any losses incurred under certain of the guarantee obligations that remain with Spectra Capital. At December 31, 2019, the maximum potential amount of future payments associated with these guarantees were $65 million, the majority of which expires by 2028.

In October 2017, ACP executed a $3.4 billion revolving credit facility with a stated maturity date of October 2021. Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $827 million as of December 31, 2019. This amount represents 47% of the outstanding borrowings under the credit facility.

In addition to the Spectra Capital and ACP revolving credit facility guarantees above, Duke Energy has issued performance guarantees to customers and other third parties that guarantee the payment and performance of other parties, including certain non-wholly owned entities, as well as guarantees of debt of certain non-consolidated entities. If such entities were to default on payments or performance, Duke Energy would be required under the guarantees to make payments on the obligations of these entities. The maximum potential amount of future payments required under these guarantees as of December 31, 2019, was $128 million, of which, $114 million expire between 2020 and 2030, with the remaining performance guarantees having no contractual expiration. Additionally, certain guarantees have uncapped maximum potential payments; however, Duke Energy does not believe these guarantees will have a material effect on its results of operations, cash flows or financial position.

Duke Energy uses bank-issued standby letters of credit to secure the performance of wholly owned and non-wholly owned entities to a third party or customer. Under these arrangements, Duke Energy has payment obligations to the issuing bank that are triggered by a draw by the third party or customer due to the failure of the wholly owned or non-wholly owned entity to perform according to the terms of its underlying contract. At December 31, 2019, Duke Energy had issued a total of $634 million in letters of credit, which expire between 2020 and 2022. The unused amount under these letters of credit was $81 million.

Duke Energy recognized $23 million as of December 31, 2019, and 2018, primarily in Other within Other Noncurrent Liabilities on the Consolidated Balance Sheets, for the guarantees discussed above. As current estimates change, additional losses related to guarantees and indemnifications to third parties, which could be material, may be recorded by the Duke Energy Registrants in the future.

9. JOINT OWNERSHIP OF GENERATING AND TRANSMISSION FACILITIES

The Duke Energy Registrants maintain ownership interests in certain jointly owned generating and transmission facilities. The Duke Energy Registrants are entitled to a share of the generating capacity and output of each unit equal to their respective ownership interests. The Duke Energy Registrants pay their ownership share of additional construction costs, fuel inventory purchases and operating expenses. The Duke Energy Registrants share of revenues and operating costs of the jointly owned facilities is included within the corresponding line in the Consolidated Statements of Operations. Each participant in the jointly owned facilities must provide its own financing.

The following table presents the Duke Energy Registrants' interest of jointly owned plant or facilities and amounts included on the Consolidated Balance Sheets. All facilities are operated by the Duke Energy Registrants and are included in the Electric Utilities and Infrastructure segment.

	December 31, 2019			
(in millions except for ownership interest)	**Ownership Interest**	**Property, Plant and Equipment**	**Accumulated Depreciation**	**Construction Work in Progress**
Duke Energy Carolinas				
Catawba (units 1 and 2)[a]	**19.25%**	**$ 1,011**	**$ 510**	**$ 21**
W.S. Lee CC[b]	**87.27%**	**609**	**32**	**1**
Duke Energy Indiana				
Gibson (unit 5)[c]	**50.05%**	**410**	**183**	**3**
Vermillion[d]	**62.50%**	**172**	**119**	**—**
Transmission and local facilities[c]	**Various**	**5,421**	**1,436**	**172**

(a) Jointly owned with North Carolina Municipal Power Agency Number 1, NCEMC and PMPA.
(b) Jointly owned with NCEMC.
(c) Jointly owned with WVPA and IMPA.
(d) Jointly owned with WVPA.

10. ASSET RETIREMENT OBLIGATIONS

Duke Energy 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. Certain assets of the Duke Energy Registrants have an indeterminate life, such as transmission and distribution facilities, and thus the fair value of the retirement obligation is not reasonably estimable. A liability for these AROs will be recorded when a fair value is determinable.

The Duke Energy Registrants' regulated operations accrue costs of removal for property that does not have an associated legal retirement obligation based on regulatory orders from state commissions. These costs of removal are recorded as a regulatory liability in accordance with regulatory accounting treatment. The Duke Energy Registrants do not accrue the estimated cost of removal for any nonregulated assets. See Note 4 for the estimated cost of removal for assets without an associated legal retirement obligation, which are included in Regulatory liabilities on the Consolidated Balance Sheets.

The following table presents the AROs recorded on the Consolidated Balance Sheets.

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Decommissioning of nuclear power facilities[a]	$ 6,633	$ 2,551	$ 4,028	$ 3,499	$ 529	$ —	$ —	$ —
Closure of ash impoundments	6,333	3,118	2,368	2,352	16	41	805	—
Other	352	65	75	42	33	39	27	17
Total asset retirement obligation	$ 13,318	$ 5,734	$ 6,471	$ 5,893	$ 578	$ 80	$ 832	$ 17
Less: current portion	881	206	485	485	—	1	189	—
Total noncurrent asset retirement obligation	$ 12,437	$ 5,528	$ 5,986	$ 5,408	$ 578	$ 79	$ 643	$ 17

(a) Duke Energy amount includes purchase accounting adjustments related to the merger with Progress Energy.

Nuclear Decommissioning Liability

AROs related to nuclear decommissioning are based on site-specific cost studies. The NCUC, PSCSC and FPSC require updated cost estimates for decommissioning nuclear plants every five years.

The following table summarizes information about the most recent site-specific nuclear decommissioning cost studies. Decommissioning costs are stated in 2018 or 2019 dollars, depending on the year of the cost study, and include costs to decommission plant components not subject to radioactive contamination.

(in millions)	Annual Funding Requirement[a]	Decommissioning Costs[a]	Year of Cost Study
Duke Energy	$ 24	$ 9,152	2018 and 2019
Duke Energy Carolinas[b][c]	—	4,365	2018
Duke Energy Progress[d]	24	4,181	2019
Duke Energy Florida[e]	—	606	2019

(a) Amounts for Progress Energy equal the sum of Duke Energy Progress and Duke Energy Florida.

(b) Decommissioning cost for Duke Energy Carolinas reflects its ownership interest in jointly owned reactors. Other joint owners are responsible for decommissioning costs related to their interest in the reactors.

(c) Duke Energy Carolinas' site-specific nuclear decommissioning cost study completed in 2018 was filed with the NCUC and PSCSC in 2019. A new funding study was also completed and filed with the NCUC and PSCSC in 2019.

(d) Duke Energy Progress' site-specific nuclear decommissioning cost study completed in 2019 is expected to be filed with the NCUC and PSCSC during the first quarter 2020. Duke Energy Progress will also complete a new funding study, which will be completed and filed with the NCUC and PSCSC in July 2020.

(e) During 2019, Duke Energy Florida reached an agreement to transfer decommissioning work for Crystal River Unit 3 to a third party. The agreement requires regulatory approval from the NRC and the FPSC. See Note 4 for more information.

Nuclear Decommissioning Trust Funds

Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida each maintain NDTFs that are intended to pay for the decommissioning costs of their respective nuclear power plants. The NDTF investments are managed and invested in accordance with applicable requirements of various regulatory bodies including the NRC, FERC, NCUC, PSCSC, FPSC and the IRS.

Use of the NDTF investments is restricted to nuclear decommissioning activities including license termination, spent fuel and site restoration. The license termination and spent fuel obligations relate to contaminated decommissioning and are recorded as AROs. The site restoration obligation relates to non-contaminated decommissioning and is recorded to cost of removal within Regulatory liabilities on the Consolidated Balance Sheets.

The following table presents the fair value of NDTF assets legally restricted for purposes of settling AROs associated with nuclear decommissioning. Duke Energy Florida is actively decommissioning Crystal River Unit 3 and was granted an exemption from the NRC, which allows for use of the NDTF for all aspects of nuclear decommissioning. The entire balance of Duke Energy Florida's NDTF may be applied toward license termination, spent fuel and site restoration costs incurred to decommission Crystal River Unit 3 and is excluded from the table below. See Note 17 for additional information related to the fair value of the Duke Energy Registrants' NDTFs.

	December 31,	
(in millions)	**2019**	**2018**
Duke Energy	**$ 6,766**	$ 5,579
Duke Energy Carolinas	**3,837**	3,133
Duke Energy Progress	**2,929**	2,446

Nuclear Operating Licenses

Operating licenses for nuclear units are potentially subject to extension. The following table includes the current expiration of nuclear operating licenses.

Unit	Year of Expiration
Duke Energy Carolinas	
Catawba Units 1 and 2	2043
McGuire Unit 1	2041
McGuire Unit 2	2043
Oconee Units 1 and 2	2033
Oconee Unit 3	2034
Duke Energy Progress	
Brunswick Unit 1	2036
Brunswick Unit 2	2034
Harris	2046
Robinson	2030

The NRC has acknowledged permanent cessation of operation and permanent removal of fuel from the reactor vessel at Crystal River Unit 3. Therefore, the license no longer authorizes operation of the reactor. In 2019, Duke Energy Florida entered into an agreement for the accelerated decommissioning of Crystal River Unit 3. The agreement is subject to the approval of the NRC and FPSC. See Note 4 for more information.

Closure of Ash Impoundments

The Duke Energy Registrants are subject to state and federal regulations covering the closure of coal ash impoundments, including the EPA CCR rule and the Coal Ash Act, and other agreements. AROs recorded on the Duke Energy Registrants' Consolidated Balance Sheets include the legal obligation for closure of coal ash basins and the disposal of related ash as a result of these regulations and agreements.

The ARO amount recorded on the Consolidated Balance Sheets is based upon estimated closure costs for impacted ash impoundments. The amount recorded represents the discounted cash flows for estimated closure costs based upon specific closure plans. 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 ash basins, consolidating material as necessary 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. The ultimate method and timetable for closure will be in compliance with standards set by federal and state regulations and other agreements. The ARO amount will be adjusted as additional information is gained through the closure and post-closure process, including acceptance and approval of compliance approaches, which may change management assumptions, and may result in a material change to the balance. See ARO Liability Rollforward section below for information on revisions made to the coal ash liability during 2019 and 2018.

Asset retirement costs associated with the AROs for operating plants and retired plants are included in Net property, plant and equipment and Regulatory assets, respectively, on the Consolidated Balance Sheets. See Note 4 for additional information on Regulatory assets related to AROs.

Cost recovery for future expenditures will be pursued through the normal ratemaking process with federal and state utility commissions, which permit recovery of necessary and prudently incurred costs associated with Duke Energy's regulated operations. See Note 4 for additional information on recovery of coal ash costs.

ARO Liability Rollforward

The following tables present changes in the liability associated with AROs.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Balance at December 31, 2017	$ 10,175	$ 3,610	$ 5,414	$ 4,673	$ 742	$ 84	$ 781	$ 15
Accretion expense[a]	427	179	225	196	29	4	29	1
Liabilities settled[b]	(638)	(281)	(272)	(227)	(45)	(5)	(79)	—
Liabilities incurred in the current year[c]	39	8	5	—	5	—	25	—
Revisions in estimates of cash flows	464	433	39	178	(140)	10	(34)	3
Balance at December 31, 2018	10,467	3,949	5,411	4,820	591	93	722	19
Accretion expense[a]	**508**	**235**	**252**	**227**	**25**	**3**	**28**	**1**
Liabilities settled[b]	**(895)**	**(329)**	**(499)**	**(460)**	**(39)**	**(12)**	**(54)**	**—**
Liabilities incurred in the current year	**25**	**18**	**7**	**—**	**7**	**—**	**—**	**—**
Revisions in estimates of cash flows[d]	**3,213**	**1,861**	**1,300**	**1,306**	**(6)**	**(4)**	**136**	**(3)**
Balance at December 31, 2019	**$ 13,318**	**$ 5,734**	**$ 6,471**	**$ 5,893**	**$ 578**	**$ 80**	**$ 832**	**$ 17**

(a) Substantially all accretion expense for the years ended December 31, 2019, and 2018, relates to Duke Energy's regulated operations and has been deferred in accordance with regulatory accounting treatment.

(b) Amounts primarily relate to ash impoundment closures and nuclear decommissioning of Crystal River Unit 3.

(c) Amounts primarily relate to AROs recorded as a result of state agency closure requirements at Duke Energy Indiana.

(d) Amounts primarily relate to increases in closure estimates for certain ash impoundments as a result of the NCDEQ's April 1 Order and the related settlement agreement dated December 31, 2019. See Note 5 for more information. The amount recorded in the fourth quarter of 2019 for coal ash closures as a result of the settlement was not material.

11. PROPERTY, PLANT AND EQUIPMENT

The following tables summarize the property, plant and equipment for Duke Energy and its subsidiary registrants.

		December 31, 2019							
(in millions)	Estimated Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 2,091	$ 520	$ 884	$ 449	$ 435	$ 150	$ 117	$ 388
Plant – Regulated									
Electric generation, distribution and transmission	15-100	111,739	42,723	48,142	30,018	18,124	5,838	15,032	—
Natural gas transmission and distribution	4-73	9,839	—	—	—	—	2,892	—	6,947
Other buildings and improvements	23-90	1,810	714	401	162	239	269	278	148
Plant – Nonregulated									
Electric generation, distribution and transmission	5-30	5,103	—	—	—	—	—	—	—
Other buildings and improvements	25-35	488	—	—	—	—	—	—	—
Nuclear fuel		3,253	1,891	1,362	1,362	—	—	—	—
Equipment	3-25	2,313	546	665	452	213	319	205	128
Construction in process		6,102	1,389	2,149	1,114	1,035	504	381	531
Other	2-40	4,916	1,139	1,467	1,046	411	269	292	304
Total property, plant and equipment[a][e]		147,654	48,922	55,070	34,603	20,457	10,241	16,305	8,446
Total accumulated depreciation – regulated[b][c]		(43,419)	(16,525)	(17,159)	(11,915)	(5,236)	(2,843)	(5,233)	(1,681)
Total accumulated depreciation – nonregulated[d][e]		(2,354)	—	—	—	—	—	—	—
Generation facilities to be retired, net		246	—	246	246	—	—	—	—
Total net property, plant and equipment		$ 102,127	$ 32,397	$ 38,157	$ 22,934	$ 15,221	$ 7,398	$ 11,072	$ 6,765

(a) Includes finance leases of $952 million, $211 million, $443 million, $308 million, $135 million and $10 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana, respectively, primarily within Plant – Regulated. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $143 million, $17 million and $126 million, respectively, of accumulated amortization of finance leases.

(b) Includes $1,807 million, $1,082 million, $725 million and $725 million of accumulated amortization of nuclear fuel at Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.

(c) Includes accumulated amortization of finance leases of $6 million, $13 million and $3 million at Duke Energy, Duke Energy Carolinas and Duke Energy Indiana, respectively.

(d) Includes accumulated amortization of finance leases of $20 million at Duke Energy.

(e) Includes gross property, plant and equipment cost of consolidated VIEs of $5,747 million and accumulated depreciation of consolidated VIEs of $1,041 million at Duke Energy.

During the year ended December 31, 2019, Duke Energy evaluated recoverability of the wind and solar generation assets included in the minority interest sale as a result of the portfolio fair value of consideration received being less than the carrying value of the assets and determined the assets were all recoverable. Additionally, in 2019, Duke Energy evaluated recoverability of its renewable merchant plants principally located in the Electric Reliability Council of Texas West market due to declining market pricing and declining long-term forecasted energy prices, primarily driven by lower forecasted natural gas prices. Duke Energy determined that the assets were not impaired because the carrying value of $160 million approximates the aggregate estimated future cash flows. A continued decline in energy market pricing would likely result in a future impairment.

		December 31, 2018							
(in millions)	Estimated Useful Life (Years)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Land		$ 2,072	$ 472	$ 868	$ 445	$ 423	$ 136	$ 116	$ 448
Plant – Regulated									
Electric generation, distribution and transmission	15-100	100,706	38,468	42,760	26,147	16,613	5,182	14,292	—
Natural gas transmission and distribution	12-80	8,808	—	—	—	—	2,719	—	6,089
Other buildings and improvements	24-90	1,966	681	636	295	341	270	253	126
Plant – Nonregulated									
Electric generation, distribution and transmission	5-30	4,410	—	—	—	—	—	—	—
Other buildings and improvements	25-35	494	—	—	—	—	—	—	—
Nuclear fuel		3,460	1,898	1,562	1,562	—	—	—	—
Equipment	3-55	2,141	467	565	399	166	384	178	141
Construction in process		5,726	1,678	2,515	1,659	856	412	325	382
Other	3-40	4,675	1,077	1,354	952	393	257	279	300
Total property, plant and equipment(a)(d)		134,458	44,741	50,260	31,459	18,792	9,360	15,443	7,486
Total accumulated depreciation – regulated(b)(c)(d)		(41,079)	(15,496)	(16,398)	(11,423)	(4,968)	(2,717)	(4,914)	(1,575)
Total accumulated depreciation – nonregulated(c)(d)		(2,047)	—	—	—	—	—	—	—
Generation facilities to be retired, net		362	—	362	362	—	—	—	—
Total net property, plant and equipment		$ 91,694	$ 29,245	$ 34,224	$ 20,398	$ 13,824	$ 6,643	$ 10,529	$ 5,911

(a) Includes finance leases of $1,237 million, $135 million, $257 million, $137 million, $120 million, $73 million and $35 million at Duke Energy, Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio and Duke Energy Indiana, respectively, primarily within Plant – Regulated. The Progress Energy, Duke Energy Progress and Duke Energy Florida amounts are net of $131 million, $14 million and $117 million, respectively, of accumulated amortization of finance leases.

(b) Includes $1,947 million, $1,087 million, $860 million and $860 million of accumulated amortization of nuclear fuel at Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Progress, respectively.

(c) Includes accumulated amortization of finance leases of $61 million, $12 million, $20 million and $10 million at Duke Energy, Duke Energy Carolinas, Duke Energy Ohio and Duke Energy Indiana, respectively.

(d) Includes gross property, plant and equipment cost of consolidated VIEs of $4,007 million and accumulated depreciation of consolidated VIEs of $698 million at Duke Energy.

During the year ended December 31, 2017, Duke Energy recorded a pretax impairment charge of $69 million on a wholly owned non-contracted wind project. The impairment was recorded within Impairment charges on Duke Energy's Consolidated Statements of Operations. $58 million of the impairment related to property, plant and equipment and $11 million of the impairment related to a net intangible asset. The charge represents the excess carrying value over the estimated fair value of the project, which was based on a Level 3 Fair Value measurement that was determined from the income approach using discounted cash flows. The impairment was primarily due to the non-contracted wind project being located in a market that has experienced continued declining market pricing during 2017 and declining long-term forecasted energy and capacity prices, driven by low natural gas prices, additional renewable generation placed in service and lack of significant load growth.

The following tables present capitalized interest, which includes the debt component of AFUDC.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Duke Energy	**$ 159**	$ 161	$ 128
Duke Energy Carolinas	**30**	35	45
Progress Energy	**31**	51	45
Duke Energy Progress	**28**	26	21
Duke Energy Florida	**3**	25	24
Duke Energy Ohio	**22**	17	10
Duke Energy Indiana	**26**	27	9
Piedmont	**26**	17	12

12. GOODWILL AND INTANGIBLE ASSETS

GOODWILL

Duke Energy

The following table presents goodwill by reportable segment for Duke Energy included on Duke Energy's Consolidated Balance Sheets at December 31, 2019, and 2018.

(in millions)	Electric Utilities and Infrastructure	Gas Utilities and Infrastructure	Commercial Renewables	Total
Goodwill Balance at December 31, 2018	$ 17,379	$ 1,924	$ 122	$ 19,425
Accumulated impairment charges[a]	—	—	(122)	(122)
Goodwill balance at December 31, 2018, adjusted for accumulated impairment charges	$ 17,379	$ 1,924	$ —	$ 19,303
Goodwill Balance at December 31, 2019	**$ 17,379**	**$ 1,924**	**$ 122**	**$ 19,425**
Accumulated impairment charges[a]	—	—	**(122)**	**(122)**
Goodwill balance at December 31, 2019, adjusted for accumulated impairment charges	**$ 17,379**	**$ 1,924**	**$ —**	**$ 19,303**

(a) Duke Energy evaluated the recoverability of goodwill during 2018 and 2017 and recorded impairment charges of $93 million and $29 million, respectively, related to the Commercial Renewables reporting unit included in Impairment charges on Duke Energy's Consolidated Statements of Operations. The fair value of the reporting unit was determined based on the income approach and market approach in 2018 and 2017, respectively. See "Goodwill Impairment Testing" below for the results of the 2019 goodwill impairment test.

Duke Energy Ohio

Duke Energy Ohio's Goodwill balance of $920 million, allocated $596 million to Electric Utilities and Infrastructure and $324 million to Gas Utilities and Infrastructure, is presented net of accumulated impairment charges of $216 million on the Consolidated Balance Sheets at December 31, 2019, and 2018.

Progress Energy

Progress Energy's Goodwill is included in the Electric Utilities and Infrastructure segment and there are no accumulated impairment charges.

Piedmont

Piedmont's Goodwill is included in the Gas Utilities and Infrastructure segment and there are no accumulated impairment charges.

Goodwill Impairment Testing

Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont are required to perform an annual goodwill impairment test as of the same date each year and, accordingly, perform their annual impairment testing of goodwill as of August 31. Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont update their test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value. As the fair value for Duke Energy, Progress Energy, Duke Energy Ohio and Piedmont exceeded their respective carrying values at the date of the annual impairment analysis, no goodwill impairment charges were recorded in 2019.

INTANGIBLE ASSETS

The following tables show the carrying amount and accumulated amortization of intangible assets included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets of the Duke Energy Registrants at December 31, 2019, and 2018.

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Emission allowances	$ 18	$ —	$ 5	$ 2	$ 3	$ —	$ 12	$ —
Renewable energy certificates	172	53	118	118	—	1	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	89	—	—	—	—	—	—	—
Other	2	—	—	—	—	—	—	—
Total gross carrying amounts	305	53	123	120	3	1	36	—
Accumulated amortization – natural gas, coal and power contracts	(21)	—	—	—	—	—	(21)	—
Accumulated amortization – renewable operating and development projects	(34)	—	—	—	—	—	—	—
Accumulated amortization – other	(1)	—	—	—	—	—	—	—
Total accumulated amortization	(56)	—	—	—	—	—	(21)	—
Total intangible assets, net	$ 249	$ 53	$ 123	$ 120	$ 3	$ 1	$ 15	$ —

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Emission allowances	$ 18	$ —	$ 5	$ 2	$ 3	$ —	$ 12	$ —
Renewable energy certificates	168	46	120	120	—	2	—	—
Natural gas, coal and power contracts	24	—	—	—	—	—	24	—
Renewable operating and development projects	84	—	—	—	—	—	—	—
Other	6	—	—	—	—	—	—	3
Total gross carrying amounts	300	46	125	122	3	2	36	3
Accumulated amortization – natural gas, coal and power contracts	(20)	—	—	—	—	—	(20)	—
Accumulated amortization – renewable operating and development projects	(29)	—	—	—	—	—	—	—
Accumulated amortization – other	(5)	—	—	—	—	—	—	(3)
Total accumulated amortization	(54)	—	—	—	—	—	(20)	(3)
Total intangible assets, net	$ 246	$ 46	$ 125	$ 122	$ 3	$ 2	$ 16	$ —

See Note 11 for information related to 2017 impairment charge.

Amortization Expense

Amortization expense amounts for natural gas, coal and power contracts, renewable operating projects and other intangible assets are immaterial for the years ended December 31, 2019, 2018 and 2017, and are expected to be immaterial for the next five years as of December 31, 2019.

13. INVESTMENTS IN UNCONSOLIDATED AFFILIATES

EQUITY METHOD INVESTMENTS

Investments in affiliates that are not controlled by Duke Energy, but over which it has significant influence, are accounted for using the equity method.

The following table presents Duke Energy's investments in unconsolidated affiliates accounted for under the equity method, as well as the respective equity in earnings, by segment.

	Years Ended December 31,					
	2019		2018		2017	
(in millions)	Investments	Equity in earnings	Investments	Equity in earnings	Investments	Equity in earnings
Electric Utilities and Infrastructure	**$ 122**	**$ 9**	$ 97	$ 6	$ 89	$ 5
Gas Utilities and Infrastructure	**1,388**	**114**	1,003	27	763	62
Commercial Renewables	**314**	**(4)**	201	(1)	190	(5)
Other	**112**	**43**	108	51	133	57
Total	**$ 1,936**	**$ 162**	$ 1,409	$ 83	$ 1,175	$ 119

During the years ended December 31, 2019, 2018 and 2017, Duke Energy received distributions from equity investments of $55 million, $108 million and $13 million, respectively, which are included in Other assets within Cash Flows from Operating Activities on the Consolidated Statements of Cash Flows. During the years ended December 31, 2019, 2018 and 2017, Duke Energy received distributions from equity investments of $11 million, $137 million and $281 million, respectively, which are included in Return of investment capital within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

During the years ended December 31, 2019, 2018 and 2017, Piedmont received distributions from equity investments of $1 million, $1 million and $4 million, respectively, which are included in Other assets within Cash Flows from Operating Activities and $4 million, $3 million and $2 million, respectively, which are included within Cash Flows from Investing Activities on the Consolidated Statements of Cash Flows.

Significant investments in affiliates accounted for under the equity method are discussed below.

Electric Utilities and Infrastructure

Duke Energy owns a 50% interest in DATC and in Pioneer, which build, own and operate electric transmission facilities in North America.

Gas Utilities and Infrastructure

The table below outlines Duke Energy's ownership interests in natural gas pipeline companies and natural gas storage facilities.

Entity Name	Ownership Interest	Investment Amount (in millions) December 31, 2019	Investment Amount (in millions) December 31, 2018
Pipeline Investments			
ACP	47%	**$ 1,179**	$ 797
Sabal Trail	7.5%	**121**	112 (c)
Constitution	24%	**—**	25
Cardinal[a]	21.49%	**9**	10
Storage Facilities			
Pine Needle[a]	45%	**28**	13
Hardy Storage[a]	50%	**51**	46
Total Investments[b]		**$ 1,388**	$ 1,003

(a) Piedmont owns the Cardinal, Pine Needle and Hardy Storage investments.
(b) Duke Energy includes purchase accounting adjustments related to Piedmont.
(c) Sabal Trail returned capital of $112 million during the year ended December 31, 2018.

In October 2017, Duke Energy entered into a guarantee agreement to support its share of the ACP revolving credit facility. See Note 8 for additional information. As a result of the financing, ACP returned capital of $265 million to Duke Energy.

During 2018 and 2019, ACP received several adverse court rulings as described in Note 4. As a result, Duke Energy evaluated this investment for impairment and determined that fair value approximated carrying value and therefore no impairment was necessary.

For regulatory matters and other information on the ACP, Sabal Trail and Constitution investments, see Notes 4 and 18.

Commercial Renewables

DS Cornerstone, LLC, which owns wind farm projects in the U.S. was part of a sale of minority interest in a certain portion of renewable assets to John Hancock in 2019. See Note 2 for more information on the sale. Prior to the sale, Duke Energy had a 50% interest in DS Cornerstone, LLC. After the sale, Duke Energy has a 26% interest in the investment.

In 2019, Duke Energy acquired a majority ownership in a portfolio of distributed fuel cell projects from Bloom Energy Corporation. Duke Energy is not the primary beneficiary of the assets within the portfolio and does not consolidate the assets in the portfolio.

Impairment of Equity Method Investments

Duke Energy recorded OTTIs of the Constitution investment within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Operations of $25 million and $55 million for the years ended December 31, 2019, and 2018, respectively. The current year charge resulted in the full write-down of Duke Energy's investment in Constitution. The impairments were primarily due to the continued delay in resolving project uncertainty through the courts and regulatory bodies, as well as recent pricing concerns between the customers and owners. For additional information on the Constitution investment, see Note 4.

Other

Duke Energy owns a 17.5% indirect interest in NMC, which owns and operates a methanol and MTBE business in Jubail, Saudi Arabia. Duke Energy's economic ownership interest decreased from 25% to 17.5% with the successful startup of NMC's polyacetal production facility in 2017. Duke Energy retains 25% of the board representation and voting rights of NMC.

14. RELATED PARTY TRANSACTIONS

The Subsidiary Registrants engage in related party transactions in accordance with the applicable state and federal commission regulations. Refer to the Consolidated Balance Sheets of the Subsidiary Registrants for balances due to or due from related parties. Material amounts related to transactions with related parties included in the Consolidated Statements of Operations and Comprehensive Income are presented in the following table.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Duke Energy Carolinas			
Corporate governance and shared service expenses[a]	**$ 841**	$ 985	$ 858
Indemnification coverages[b]	**20**	22	23
Joint Dispatch Agreement (JDA) revenue[c]	**60**	84	49
JDA expense[c]	**186**	207	145
Intercompany natural gas purchases[d]	**15**	15	9
Progress Energy			
Corporate governance and shared service expenses[a]	**$ 778**	$ 906	$ 736
Indemnification coverages[b]	**37**	34	38
JDA revenue[c]	**186**	207	145
JDA expense[c]	**60**	84	49
Intercompany natural gas purchases[d]	**76**	78	77
Duke Energy Progress			
Corporate governance and shared service expenses[a]	**$ 462**	$ 577	$ 438
Indemnification coverages[b]	**15**	13	15
JDA revenue[c]	**186**	207	145
JDA expense[c]	**60**	84	49
Intercompany natural gas purchases[d]	**76**	78	77
Duke Energy Florida			
Corporate governance and shared service expenses[a]	**$ 316**	$ 329	$ 298
Indemnification coverages[b]	**22**	21	23
Duke Energy Ohio			
Corporate governance and shared service expenses[a]	**$ 354**	$ 374	$ 363
Indemnification coverages[b]	**4**	5	5
Duke Energy Indiana			
Corporate governance and shared service expenses[a]	**$ 412**	$ 405	$ 370
Indemnification coverages[b]	**7**	7	8
Piedmont			
Corporate governance and shared service expenses[a]	**$ 138**	$ 170	$ 50
Indemnification coverages[b]	**3**	2	2
Intercompany natural gas sales[d]	**91**	93	86
Natural gas storage and transportation costs[e]	**23**	25	25

(a) The Subsidiary Registrants are charged their proportionate share of corporate governance and other shared services costs, primarily related to human resources, employee benefits, information technology, legal and accounting fees, as well as other third-party costs. These amounts are primarily recorded in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income.

(b) The Subsidiary Registrants incur expenses related to certain indemnification coverages through Bison, Duke Energy's wholly owned captive insurance subsidiary. These expenses are recorded in Operation, maintenance and other on the Consolidated Statements of Operations and Comprehensive Income.

(c) Duke Energy Carolinas and Duke Energy Progress participate in a JDA, which allows the collective dispatch of power plants between the service territories to reduce customer rates. Revenues from the sale of power and expenses from the purchase of power pursuant to the JDA are recorded in Operating Revenues and Fuel used in electric generation and purchased power, respectively, on the Consolidated Statements of Operations and Comprehensive Income.

(d) Piedmont provides long-term natural gas delivery service to certain Duke Energy Carolinas and Duke Energy Progress natural gas-fired generation facilities. Piedmont records the sales in Operating Revenues, and Duke Energy Carolinas and Duke Energy Progress record the related purchases as a component of Fuel used in electric generation and purchased power on their respective Consolidated Statements of Operations and Comprehensive Income. These intercompany revenues and expenses are eliminated in consolidation.

(e) Piedmont has related party transactions as a customer of its equity method investments in Pine Needle, Hardy Storage, and Cardinal natural gas storage and transportation facilities. These expenses are included in Cost of natural gas on Piedmont's Consolidated Statements of Operations and Comprehensive Income.

In addition to the amounts presented above, the Subsidiary Registrants have other affiliate transactions, including rental of office space, participation in a money pool arrangement, other operational transactions and their proportionate share of certain charged expenses. See Note 7 for more information regarding money pool. These transactions of the Subsidiary Registrants are incurred in the ordinary course of business and are eliminated in consolidation.

As discussed in Note 18, certain trade receivables have been sold by Duke Energy Ohio and Duke Energy Indiana to CRC, an affiliate formed by a subsidiary of Duke Energy. The proceeds obtained from the sales of receivables are largely cash but do include a subordinated note from CRC for a portion of the purchase price.

Intercompany Income Taxes

Duke Energy and the Subsidiary Registrants file a consolidated federal income tax return and other state and jurisdictional returns. The Subsidiary Registrants have a tax sharing agreement with Duke Energy for the allocation of consolidated tax liabilities and benefits. Income taxes recorded represent amounts the Subsidiary Registrants would incur as separate C-Corporations. The following table includes the balance of intercompany income tax receivables and payables for the Subsidiary Registrants.

(in millions)	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
December 31, 2019							
Intercompany income tax receivable	$ —	$ 125	$ 28	$ —	$ 9	$ 28	$ 13
Intercompany income tax payable	5	—	—	2	—	—	—
December 31, 2018							
Intercompany income tax receivable	$ 52	$ 47	$ 29	$ —	$ —	$ 8	$ —
Intercompany income tax payable	—	—	—	16	3	—	45

15. DERIVATIVES AND HEDGING

The Duke Energy Registrants use commodity and interest rate contracts to manage commodity price risk and interest rate risk. The primary use of commodity derivatives is to hedge the generation portfolio against changes in the prices of electricity and natural gas. Piedmont enters into natural gas supply contracts to provide diversification, reliability and natural gas cost benefits to its customers. Interest rate derivatives are used to manage interest rate risk associated with borrowings.

All derivative instruments not identified as NPNS are recorded at fair value as assets or liabilities on the Consolidated Balance Sheets. Cash collateral related to derivative instruments executed under master netting arrangements is offset against the collateralized derivatives on the Consolidated Balance Sheets. The cash impacts of settled derivatives are recorded as operating activities on the Consolidated Statements of Cash Flows.

INTEREST RATE RISK

The Duke Energy Registrants are exposed to changes in interest rates as a result of their issuance or anticipated issuance of variable-rate and fixed-rate debt and commercial paper. Interest rate risk is managed by limiting variable-rate exposures to a percentage of total debt and by monitoring changes in interest rates. To manage risk associated with changes in interest rates, the Duke Energy Registrants may enter into interest rate swaps, U.S. Treasury lock agreements and other financial contracts. In anticipation of certain fixed-rate debt issuances, a series of forward-starting interest rate swaps or Treasury locks may be executed to lock in components of current market interest rates. These instruments are later terminated prior to or upon the issuance of the corresponding debt.

Cash Flow Hedges

For a derivative designated as hedging the exposure to variable cash flows of a future transaction, referred to as a cash flow hedge, the effective portion of the derivative's gain or loss is initially reported as a component of other comprehensive income and subsequently reclassified into earnings once the future transaction impacts earnings. Amounts for interest rate contracts are reclassified to earnings as interest expense over the term of the related debt. Gains and losses reclassified out of AOCI for the years ended December 31, 2019, 2018 and 2017 were not material. Duke Energy's interest rate derivatives designated as hedges include interest rate swaps used to hedge existing debt within the Commercial Renewables business and forward-starting interest rate swaps not accounted for under regulatory accounting.

Undesignated Contracts

Undesignated contracts primarily include contracts not designated as a hedge because they are accounted for under regulatory accounting or contracts that do not qualify for hedge accounting.

Duke Energy's interest rate swaps for its regulated operations employ regulatory accounting. With regulatory accounting, the mark-to-market gains or losses on the swaps are deferred as regulatory liabilities or regulatory assets, respectively. Regulatory assets and liabilities are amortized consistent with the treatment of the related costs in the ratemaking process. The accrual of interest on the swaps is recorded as Interest Expense on the Duke Energy Registrant's Consolidated Statements of Operations and Comprehensive Income.

The following tables show notional amounts of outstanding derivatives related to interest rate risk.

	December 31, 2019					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**
Cash flow hedges	**$ 993**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Undesignated contracts	**1,277**	**450**	**800**	**250**	**550**	**27**
Total notional amount[a]	**$ 2,270**	**$ 450**	**$ 800**	**$ 250**	**$ 550**	**$ 27**

	December 31, 2018					
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**
Cash flow hedges[a]	$ 923	$ —	$ —	$ —	$ —	$ —
Undesignated contracts	1,721	300	1,200	650	550	27
Total notional amount	$ 2,644	$ 300	$ 1,200	$ 650	$ 550	$ 27

(a) Duke Energy includes amounts related to consolidated VIEs of $693 million in cash flow hedges as of December 31, 2019, and $422 million in cash flow hedges and $194 million in undesignated contracts as of December 31, 2018.

COMMODITY PRICE RISK

The Duke Energy Registrants are exposed to the impact of changes in the prices of electricity purchased and sold in bulk power markets and coal and natural gas purchases, including Piedmont's natural gas supply contracts. Exposure to commodity price risk is influenced by a number of factors including the term of contracts, the liquidity of markets and delivery locations. For the Subsidiary Registrants, bulk power electricity and coal and natural gas purchases flow through fuel adjustment clauses, formula based contracts or other cost sharing mechanisms. Differences between the costs included in rates and the incurred costs, including undesignated derivative contracts, are largely deferred as regulatory assets or regulatory liabilities. Piedmont policies allow for the use of financial instruments to hedge commodity price risks. The strategy and objective of these hedging programs are to use the financial instruments to reduce gas cost volatility for customers.

Volumes

The tables below include volumes of outstanding commodity derivatives. Amounts disclosed represent the absolute value of notional volumes of commodity contracts excluding NPNS. The Duke Energy Registrants have netted contractual amounts where offsetting purchase and sale contracts exist with identical delivery locations and times of delivery. Where all commodity positions are perfectly offset, no quantities are shown.

	December 31, 2019							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (GWh)	**15,858**	**—**	**—**	**—**	**—**	**1,887**	**13,971**	**—**
Natural gas (millions of Dth)	**704**	**130**	**160**	**160**	**—**	**—**	**3**	**411**

	December 31, 2018							
	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electricity (GWh)	15,286	—	—	—	—	1,786	13,500	—
Natural gas (millions of Dth)	739	121	169	166	3	—	1	448

U.S. EQUITY SECURITIES RISK

In May 2019, Duke Energy Florida entered into a Decommissioning Services Agreement for the accelerated decommissioning of Crystal River Unit 3 with ADP CR3, LLC and ADP SF1, LLC. See Note 4 for additional information on the accelerated decommissioning. Duke Energy Florida executed U.S. equity option collars within the NDTF in May 2019 to preserve the U.S. equity portfolio value in the Duke Energy Florida NDTF in the event the accelerated decommissioning is approved. These option collars were executed as a purchase of a put option and the sale of a call option on certain U.S. equity index funds. The put and call options create a collar to guarantee a minimum and maximum investment value for the Duke Energy Florida NDTF U.S. equity portfolio. The put and call options were entered into at zero-cost, with the price to purchase the puts offset entirely by the funds received to sell the calls. As of December 31, 2019, the aggregate notional amount of both the put and call options was 305,000 units in U.S. equity security index funds. The options are not designated as hedging instruments. Substantially all of Duke Energy Florida's NDTF qualifies for regulatory accounting. With regulatory accounting, the mark-to-market gains or losses on the options are deferred as regulatory liabilities or regulatory assets, respectively.

LOCATION AND FAIR VALUE OF DERIVATIVE ASSETS AND LIABILITIES RECOGNIZED IN THE CONSOLIDATED BALANCE SHEETS

The following tables show the fair value and balance sheet location of derivative instruments. Although derivatives subject to master netting arrangements are netted on the Consolidated Balance Sheets, the fair values presented below are shown gross and cash collateral on the derivatives has not been netted against the fair values shown.

Derivative Assets	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 17	$ —	$ —	$ —	$ —	$ 3	$ 13	$ 1
Noncurrent	1	—	—	—	—	1	—	—
Total Derivative Assets – Commodity Contracts	$ 18	$ —	$ —	$ —	$ —	$ 4	$ 13	$ 1
Interest Rate Contracts								
Not Designated as Hedging Instruments								
Current	6	—	6	—	6	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 6	$ —	$ 6	$ —	$ 6	$ —	$ —	$ —
Equity Securities Contracts								
Not Designated as Hedging Instruments								
Current	1	—	1	—	1	—	—	—
Total Derivative Assets – Equity Securities Contracts	$ 1	$ —	$ 1	$ —	$ 1	$ —	$ —	$ —
Total Derivative Assets	$ 25	$ —	$ 7	$ —	$ 7	$ 4	$ 13	$ 1

Derivative Liabilities	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 67	$ 33	$ 26	$ 26	$ —	$ —	$ 1	$ 7
Noncurrent	156	10	37	22	—	—	—	110
Total Derivative Liabilities – Commodity Contracts	$ 223	$ 43	$ 63	$ 48	$ —	$ —	$ 1	$ 117
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 19	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	21	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	8	6	1	1	—	1	—	—
Noncurrent	5	—	—	—	—	5	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 53	$ 6	$ 1	$ 1	$ —	$ 6	$ —	$ —
Equity Securities Contracts								
Not Designated as Hedging Instruments								
Current	24	—	24	—	24	—	—	—
Total Derivative Liabilities – Equity Security Contracts	$ 24	$ —	$ 24	$ —	$ 24	$ —	$ —	$ —
Total Derivative Liabilities	$ 300	$ 49	$ 88	$ 49	$ 24	$ 6	$ 1	$ 117

Derivative Assets	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 35	$ 2	$ 2	$ 2	$ —	$ 6	$ 23	$ 3
Noncurrent	4	1	2	2	—	—	—	—
Total Derivative Assets – Commodity Contracts	$ 39	$ 3	$ 4	$ 4	$ —	$ 6	$ 23	$ 3
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 1	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	3	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	2	—	—	—	—	—	—	—
Noncurrent	12	—	—	—	—	—	—	—
Total Derivative Assets – Interest Rate Contracts	$ 18	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total Derivative Assets	$ 57	$ 3	$ 4	$ 4	$ —	$ 6	$ 23	$ 3

Derivative Liabilities	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Commodity Contracts								
Not Designated as Hedging Instruments								
Current	$ 33	$ 14	$ 10	$ 5	$ 6	$ —	$ —	$ 8
Noncurrent	158	10	15	6	—	—	—	133
Total Derivative Liabilities – Commodity Contracts	$ 191	$ 24	$ 25	$ 11	$ 6	$ —	$ —	$ 141
Interest Rate Contracts								
Designated as Hedging Instruments								
Current	$ 12	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Noncurrent	6	—	—	—	—	—	—	—
Not Designated as Hedging Instruments								
Current	23	9	13	11	2	1	—	—
Noncurrent	10	—	6	5	1	4	—	—
Total Derivative Liabilities – Interest Rate Contracts	$ 51	$ 9	$ 19	$ 16	$ 3	$ 5	$ —	$ —
Total Derivative Liabilities	$ 242	$ 33	$ 44	$ 27	$ 9	$ 5	$ —	$ 141

OFFSETTING ASSETS AND LIABILITIES

The following tables present the line items on the Consolidated Balance Sheets where derivatives are reported. Substantially all of Duke Energy's outstanding derivative contracts are subject to enforceable master netting arrangements. The gross amounts offset in the tables below show the effect of these netting arrangements on financial position and include collateral posted to offset the net position. The amounts shown are calculated by counterparty. Accounts receivable or accounts payable may also be available to offset exposures in the event of bankruptcy. These amounts are not included in the tables below.

Derivative Assets	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 24	$ —	$ 7	$ —	$ 7	$ 3	$ 13	$ 1
Gross amounts offset	(1)	—	(1)	—	(1)	—	—	—
Net amounts presented in Current Assets: Other	$ 23	$ —	$ 6	$ —	$ 6	$ 3	$ 13	$ 1
Noncurrent								
Gross amounts recognized	$ 1	$ —	$ —	$ —	$ —	$ 1	$ —	$ —
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 1	$ —	$ —	$ —	$ —	$ 1	$ —	$ —

Derivative Liabilities	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 118	$ 39	$ 51	$ 27	$ 24	$ 1	$ 1	$ 7
Gross amounts offset	(24)	—	(24)	—	(24)	—	—	—
Net amounts presented in Current Liabilities: Other	$ 94	$ 39	$ 27	$ 27	$ —	$ 1	$ 1	$ 7
Noncurrent								
Gross amounts recognized	$ 182	$ 10	$ 37	$ 22	$ —	$ 5	$ —	$ 110
Gross amounts offset	—	—	—	—	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 182	$ 10	$ 37	$ 22	$ —	$ 5	$ —	$ 110

Derivative Assets	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 38	$ 2	$ 2	$ 2	$ —	$ 6	$ 23	$ 3
Gross amounts offset	(3)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Assets: Other	$ 35	$ —	$ —	$ —	$ —	$ 6	$ 23	$ 3
Noncurrent								
Gross amounts recognized	$ 19	$ 1	$ 2	$ 2	$ —	$ —	$ —	$ —
Gross amounts offset	(3)	(1)	(2)	(2)	—	—	—	—
Net amounts presented in Other Noncurrent Assets: Other	$ 16	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Derivative Liabilities	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current								
Gross amounts recognized	$ 68	$ 23	$ 23	$ 16	$ 8	$ 1	$ —	$ 8
Gross amounts offset	(4)	(2)	(2)	(2)	—	—	—	—
Net amounts presented in Current Liabilities: Other	$ 64	$ 21	$ 21	$ 14	$ 8	$ 1	$ —	$ 8
Noncurrent								
Gross amounts recognized	$ 174	$ 10	$ 21	$ 11	$ 1	$ 4	$ —	$ 133
Gross amounts offset	(3)	(1)	(2)	(2)	—	—	—	—
Net amounts presented in Other Noncurrent Liabilities: Other	$ 171	$ 9	$ 19	$ 9	$ 1	$ 4	$ —	$ 133

OBJECTIVE CREDIT CONTINGENT FEATURES

Certain derivative contracts contain objective credit contingent features. These features include the requirement to post cash collateral or letters of credit if specific events occur, such as a credit rating downgrade below investment grade. The following tables show information with respect to derivative contracts that are in a net liability position and contain objective credit-risk-related payment provisions.

	December 31, 2019			
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress
Aggregate fair value of derivatives in a net liability position	$ 79	$ 35	$ 44	$ 44
Fair value of collateral already posted	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	79	35	44	44

	December 31, 2018			
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress
Aggregate fair value of derivatives in a net liability position	$ 44	$ 19	$ 25	$ 25
Fair value of collateral already posted	—	—	—	—
Additional cash collateral or letters of credit in the event credit-risk-related contingent features were triggered	44	19	25	25

The Duke Energy Registrants have elected to offset cash collateral and fair values of derivatives. For amounts to be netted, the derivative and cash collateral must be executed with the same counterparty under the same master netting arrangement.

16. INVESTMENTS IN DEBT AND EQUITY SECURITIES

Duke Energy's investments in debt and equity securities are primarily comprised of investments held in (i) the NDTF at Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, (ii) the grantor trusts at Duke Energy Progress, Duke Energy Florida and Duke Energy Indiana related to OPEB plans and (iii) Bison. The Duke Energy Registrants classify investments in debt securities as AFS and investments in equity securities as FV-NI.

For investments in debt securities classified as AFS, the unrealized gains and losses are included in other comprehensive income until realized, at which time, they are reported though net income. For investments in equity securities classified as FV-NI, both realized and unrealized gains and losses are reported through net income. Substantially all of Duke Energy's investments in debt and equity securities qualify for regulatory accounting, and accordingly, all associated realized and unrealized gains and losses on these investments are deferred as a regulatory asset or liability.

Duke Energy classifies the majority of investments in debt and equity securities as long term, unless otherwise noted.

Investment Trusts

The investments within the Investment Trusts are managed by independent investment managers with discretion to buy, sell and invest pursuant to the objectives set forth by the trust agreements. The Duke Energy Registrants have limited oversight of the day-to-day management of these investments. As a result, the ability to hold investments in unrealized loss positions is outside the control of the Duke Energy Registrants. Accordingly, all unrealized losses associated with debt securities within the Investment Trusts are considered OTTIs and are recognized immediately and deferred to regulatory accounts where appropriate.

Other AFS Securities

Unrealized gains and losses on all other AFS securities are included in other comprehensive income until realized, unless it is determined the carrying value of an investment is other-than-temporarily impaired. The Duke Energy Registrants analyze all investment holdings each reporting period to determine whether a decline in fair value should be considered other-than-temporary. If an OTTI exists, the unrealized credit loss is included in earnings. There were no material credit losses as of December 31, 2019, and 2018.

Other Investments amounts are recorded in Other within Other Noncurrent Assets on the Consolidated Balance Sheets.

DUKE ENERGY

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 101	$ —	$ —	$ 88
Equity securities	3,523	55	5,661	2,402	95	4,475
Corporate debt securities	37	1	603	4	13	566
Municipal bonds	13	—	368	1	4	353
U.S. government bonds	33	1	1,256	14	12	1,076
Other debt securities	3	—	141	—	2	148
Total NDTF Investments	$ 3,609	$ 57	$ 8,130	$ 2,421	$ 126	$ 6,706
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 52	$ —	$ —	$ 22
Equity securities	57	—	122	36	1	99
Corporate debt securities	3	—	67	—	2	60
Municipal bonds	4	—	94	—	1	85
U.S. government bonds	2	—	41	1	—	45
Other debt securities	—	—	56	—	1	58
Total Other Investments	$ 66	$ —	$ 432	$ 37	$ 5	$ 369
Total Investments	$ 3,675	$ 57	$ 8,562	$ 2,458	$ 131	$ 7,075

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 372
Due after one through five years	550
Due after five through 10 years	452
Due after 10 years	1,252
Total	$ 2,626

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	$ 172	$ 168
Realized losses	151	126
AFS:		
Realized gains	94	22
Realized losses	67	51

	Year Ended December 31,
(in millions)	2017
Realized gains	$ 202
Realized losses	160

DUKE ENERGY CAROLINAS

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 21	$ —	$ —	$ 29
Equity securities	1,914	8	3,154	1,309	54	2,484
Corporate debt securities	21	1	361	2	9	341
Municipal bonds	3	—	96	—	1	81
U.S. government bonds	16	1	578	5	8	475
Other debt securities	3	—	137	—	2	143
Total NDTF Investments	$ 1,957	$ 10	$ 4,347	$ 1,316	$ 74	$ 3,553

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 51
Due after one through five years	253
Due after five through 10 years	181
Due after 10 years	687
Total	$ 1,172

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	$ 113	$ 89
Realized losses	107	73
AFS:		
Realized gains	55	19
Realized losses	38	35

(in millions)	Year Ended December 31, 2017
Realized gains	$ 135
Realized losses	103

PROGRESS ENERGY

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 80**	$ —	$ —	$ 59
Equity securities	**1,609**	**47**	**2,507**	1,093	41	1,991
Corporate debt securities	**16**	**—**	**242**	2	4	225
Municipal bonds	**10**	**—**	**272**	1	3	272
U.S. government bonds	**17**	**—**	**678**	9	4	601
Other debt securities	**—**	**—**	**4**	—	—	5
Total NDTF Investments	**$ 1,652**	**$ 47**	**$ 3,783**	$ 1,105	$ 52	$ 3,153
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 49**	$ —	$ —	$ 17
Municipal bonds	**3**	**—**	**51**	—	—	47
Total Other Investments	**$ 3**	**$ —**	**$ 100**	$ —	$ —	$ 64
Total Investments	**$ 1,655**	**$ 47**	**$ 3,883**	$ 1,105	$ 52	$ 3,217

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	**$ 311**
Due after one through five years	**256**
Due after five through 10 years	**211**
Due after 10 years	**469**
Total	**$ 1,247**

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

(in millions)	Years Ended December 31, 2019	2018
FV-NI:		
Realized gains	**$ 59**	$ 79
Realized losses	**44**	53
AFS:		
Realized gains	**36**	3
Realized losses	**29**	15

(in millions)	Year Ended December 31, 2017
Realized gains	$ 65
Realized losses	56

DUKE ENERGY PROGRESS

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
NDTF						
Cash and cash equivalents	$ —	$ —	$ 53	$ —	$ —	$ 46
Equity securities	1,258	21	2,077	833	30	1,588
Corporate debt securities	16	—	242	2	3	171
Municipal bonds	10	—	272	1	3	271
U.S. government bonds	16	—	403	6	3	415
Other debt securities	—	—	4	—	—	3
Total NDTF Investments	$ 1,300	$ 21	$ 3,051	$ 842	$ 39	$ 2,494
Other Investments						
Cash and cash equivalents	$ —	$ —	$ 2	$ —	$ —	$ 6
Total Other Investments	$ —	$ —	$ 2	$ —	$ —	$ 6
Total Investments	$ 1,300	$ 21	$ 3,053	$ 842	$ 39	$ 2,500

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 34
Due after one through five years	247
Due after five through 10 years	204
Due after 10 years	436
Total	$ 921

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	**2019**	**2018**
FV-NI:		
Realized gains	**$ 38**	$ 68
Realized losses	**33**	48
AFS:		
Realized gains	**7**	2
Realized losses	**5**	10

	Year Ended December 31,
(in millions)	**2017**
Realized gains	$ 54
Realized losses	48

DUKE ENERGY FLORIDA

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are classified as FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**	**Gross Unrealized Holding Gains**	**Gross Unrealized Holding Losses**	**Estimated Fair Value**
NDTF						
Cash and cash equivalents	**$ —**	**$ —**	**$ 27**	$ —	$ —	$ 13
Equity securities	**351**	**26**	**430**	260	11	403
Corporate debt securities	**—**	**—**	**—**	—	1	54
Municipal bonds	**—**	**—**	**—**	—	—	1
U.S. government bonds	**1**	**—**	**275**	3	1	186
Other debt securities	**—**	**—**	**—**	—	—	2
Total NDTF Investments[a]	**$ 352**	**$ 26**	**$ 732**	$ 263	$ 13	$ 659
Other Investments						
Cash and cash equivalents	**$ —**	**$ —**	**$ 4**	$ —	$ —	$ 1
Municipal bonds	**3**	**—**	**51**	—	—	47
Total Other Investments	**$ 3**	**$ —**	**$ 55**	$ —	$ —	$ 48
Total Investments	**$ 355**	**$ 26**	**$ 787**	$ 263	$ 13	$ 707

During the year ended December 31, 2019, Duke Energy Florida continued to receive reimbursements from the NDTF for costs related to ongoing decommissioning activity of the Crystal River Unit 3.

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 277
Due after one through five years	9
Due after five through 10 years	7
Due after 10 years	33
Total	$ 326

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the years ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were as follows.

	Years Ended December 31,	
(in millions)	2019	2018
FV-NI:		
Realized gains	$ 21	$ 11
Realized losses	11	5
AFS:		
Realized gains	29	1
Realized losses	24	5

	Year Ended December 31,
(in millions)	2017
Realized gains	$ 11
Realized losses	8

DUKE ENERGY INDIANA

The following table presents the estimated fair value of investments in debt and equity securities; equity investments are measured at FV-NI and debt investments are classified as AFS.

	December 31, 2019			December 31, 2018		
(in millions)	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value	Gross Unrealized Holding Gains	Gross Unrealized Holding Losses	Estimated Fair Value
Investments						
Equity securities	$ 43	$ —	$ 81	$ 29	$ —	$ 67
Corporate debt securities	—	—	6	—	—	8
Municipal bonds	1	—	36	—	1	33
U.S. government bonds	—	—	2	—	—	—
Total Investments	$ 44	$ —	$ 125	$ 29	$ 1	$ 108

The table below summarizes the maturity date for debt securities.

(in millions)	December 31, 2019
Due in one year or less	$ 4
Due after one through five years	16
Due after five through 10 years	7
Due after 10 years	17
Total	$ 44

Realized gains and losses, which were determined on a specific identification basis, from sales of FV-NI and AFS securities for the year ended December 31, 2019, and 2018, and from sales of AFS securities for the year ended December 31, 2017, were insignificant.

17. FAIR VALUE MEASUREMENTS

Fair value is the exchange price to sell an asset or transfer a liability in an orderly transaction between market participants at the measurement date. The fair value definition focuses on an exit price versus the acquisition cost. Fair value measurements use market data or assumptions market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs may be readily observable, corroborated by market data, or generally unobservable. Valuation techniques maximize the use of observable inputs and minimize use of unobservable inputs. A midmarket pricing convention (the midpoint price between bid and ask prices) is permitted for use as a practical expedient.

Fair value measurements are classified in three levels based on the fair value hierarchy as defined by GAAP. Certain investments are not categorized within the fair value hierarchy. These investments are measured at fair value using the NAV per share practical expedient. The net asset value is derived based on the investment cost, less any impairment, plus or minus changes resulting from observable price changes for an identical or similar investment of the same issuer.

Fair value accounting guidance permits entities to elect to measure certain financial instruments that are not required to be accounted for at fair value, such as equity method investments or the company's own debt, at fair value. The Duke Energy Registrants have not elected to record any of these items at fair value.

Valuation methods of the primary fair value measurements disclosed below are as follows.

Investments in equity securities

The majority of investments in equity securities are valued using Level 1 measurements. Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the quarter. Principal active markets for equity prices include published exchanges such as the NYSE and Nasdaq Stock Market. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. There was no after-hours market activity that was required to be reflected in the reported fair value measurements.

Investments in debt securities

Most investments in debt securities are valued using Level 2 measurements because the valuations use interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3.

Commodity derivatives

Commodity derivatives with clearinghouses are classified as Level 1. If forward price curves are not observable for the full term of the contract and the unobservable period had more than an insignificant impact on the valuation, the commodity derivative is classified as Level 3. In isolation, increases (decreases) in natural gas forward prices result in favorable (unfavorable) fair value adjustments for natural gas purchase contracts; and increases (decreases) in electricity forward prices result in unfavorable (favorable) fair value adjustments for electricity sales contracts. Duke Energy regularly evaluates and validates pricing inputs used to estimate the fair value of natural gas commodity contracts by a market participant price verification procedure. This procedure provides a comparison of internal forward commodity curves to market participant generated curves.

Interest rate derivatives

Most over-the-counter interest rate contract derivatives are valued using financial models that utilize observable inputs for similar instruments and are classified as Level 2. Inputs include forward interest rate curves, notional amounts, interest rates and credit quality of the counterparties.

Other fair value considerations

See Note 12 for a discussion of the valuation of goodwill and intangible assets.

DUKE ENERGY

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets. Derivative amounts in the tables below for all Duke Energy Registrants exclude cash collateral, which is disclosed in Note 15. See Note 16 for additional information related to investments by major security type for the Duke Energy Registrants.

	December 31, 2019				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	**$ 5,684**	**$ 5,633**	**$ —**	**$ —**	**$ 51**
NDTF debt securities	**2,469**	**826**	**1,643**	**—**	**—**
Other equity securities	**122**	**122**	**—**	**—**	**—**
Other debt securities	**310**	**91**	**219**	**—**	**—**
Derivative assets	**25**	**3**	**7**	**15**	**—**
Total assets	**8,610**	**6,675**	**1,869**	**15**	**51**
NDTF equity security contracts	**(23)**	**—**	**(23)**	**—**	**—**
Derivative liabilities	**(277)**	**(15)**	**(145)**	**(117)**	**—**
Net assets (liabilities)	**$ 8,310**	**$ 6,660**	**$ 1,701**	**$ (102)**	**$ 51**

	December 31, 2018				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized**
NDTF equity securities	$ 4,475	$ 4,410	$ —	$ —	$ 65
NDTF debt securities	2,231	576	1,655	—	—
Other equity securities	99	99	—	—	—
Other debt securities	270	67	203	—	—
Derivative assets	57	4	25	28	—
Total assets	7,132	5,156	1,883	28	65
Derivative liabilities	(242)	(11)	(90)	(141)	—
Net assets (liabilities)	$ 6,890	$ 5,145	$ 1,793	$ (113)	$ 65

The following table provides reconciliations of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	December 31, 2019	December 31, 2018
(in millions)	**Derivatives (net)**	**Derivatives (net)**
Balance at beginning of period	**$ (113)**	$ (114)
Purchases, sales, issuances and settlements:		
Purchases	**37**	57
Settlements	**(44)**	(57)
Total gains included on the Consolidated Balance Sheet	**18**	1
Balance at end of period	**$ (102)**	$ (113)

DUKE ENERGY CAROLINAS

The following tables provide recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	**$ 3,154**	**$ 3,103**	**$ —**	**$ 51**
NDTF debt securities	**1,193**	**227**	**966**	**—**
Total assets	**4,347**	**3,330**	**966**	**51**
Derivative liabilities	**(49)**	**—**	**(49)**	**—**
Net assets	**$ 4,298**	**$ 3,330**	**$ 917**	**$ 51**

	December 31, 2018			
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Not Categorized**
NDTF equity securities	$ 2,484	$ 2,419	$ —	$ 65
NDTF debt securities	1,069	149	920	—
Derivative assets	3	—	3	—
Total assets	3,556	2,568	923	65
Derivative liabilities	(33)	—	(33)	—
Net assets	$ 3,523	$ 2,568	$ 890	$ 65

PROGRESS ENERGY

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019			December 31, 2018		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 2,530	$ 2,530	$ —	$ 1,991	$ 1,991	$ —
NDTF debt securities	1,276	599	677	1,162	427	735
Other debt securities	100	49	51	64	17	47
Derivative assets	7	—	7	4	—	4
Total assets	3,913	3,178	735	3,221	2,435	786
NDTF equity security contracts	(23)	—	(23)	—	—	—
Derivative liabilities	(65)	—	(65)	(44)	—	(44)
Net assets	$ 3,825	$ 3,178	$ 647	$ 3,177	$ 2,435	$ 742

DUKE ENERGY PROGRESS

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019			December 31, 2018		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 2,077	$ 2,077	$ —	$ 1,588	$ 1,588	$ —
NDTF debt securities	974	297	677	906	294	612
Other debt securities	2	2	—	6	6	—
Derivative assets	—	—	—	4	—	4
Total assets	3,053	2,376	677	2,504	1,888	616
Derivative liabilities	(49)	—	(49)	(27)	—	(27)
Net assets	$ 3,004	$ 2,376	$ 628	$ 2,477	$ 1,888	$ 589

DUKE ENERGY FLORIDA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019			December 31, 2018		
(in millions)	Total Fair Value	Level 1	Level 2	Total Fair Value	Level 1	Level 2
NDTF equity securities	$ 453	$ 453	$ —	$ 403	$ 403	$ —
NDTF debt securities	302	302	—	256	133	123
Other debt securities	55	4	51	48	1	47
Derivative assets	7	—	7	—	—	—
Total assets	817	759	58	707	537	170
NDTF equity security contracts	(23)	—	(23)	—	—	—
Derivative liabilities	(1)	—	(1)	(9)	—	(9)
Net assets	$ 793	$ 759	$ 34	$ 698	$ 537	$ 161

DUKE ENERGY OHIO

The recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets were not material at December 31, 2019, and 2018.

DUKE ENERGY INDIANA

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019				December 31, 2018			
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Total Fair Value	Level 1	Level 2	Level 3
Other equity securities	$ 81	$ 81	$ —	$ —	$ 67	$ 67	$ —	$ —
Other debt securities	44	—	44	—	41	—	41	—
Derivative assets	13	2	—	11	23	1	—	22
Total assets	138	83	44	11	131	68	41	22
Derivative liabilities	(1)	(1)	—	—	—	—	—	—
Total assets	$ 137	$ 82	$ 44	$ 11	$ 131	$ 68	$ 41	$ 22

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Derivatives (net)	
	Years Ended December 31,	
(in millions)	**2019**	**2018**
Balance at beginning of period	**$ 22**	$ 27
Purchases, sales, issuances and settlements:		
Purchases	**28**	50
Settlements	**(36)**	(53)
Total losses included on the Consolidated Balance Sheet	**(3)**	(2)
Balance at end of period	**$ 11**	$ 22

PIEDMONT

The following table provides recorded balances for assets and liabilities measured at fair value on a recurring basis on the Consolidated Balance Sheets.

	December 31, 2019			December 31, 2018		
(in millions)	**Total Fair Value**	**Level 1**	**Level 3**	**Total Fair Value**	**Level 1**	**Level 3**
Derivative assets	**$ 1**	**$ 1**	**$ —**	$ 3	$ 3	$ —
Derivative liabilities	**(117)**	**—**	**(117)**	(141)	—	(141)
Net (liabilities) assets	**$ (116)**	**$ 1**	**$ (117)**	$ (138)	$ 3	$ (141)

The following table provides a reconciliation of beginning and ending balances of assets and liabilities measured at fair value using Level 3 measurements.

	Derivatives (net)	
	Years Ended December 31,	
(in millions)	**2019**	**2018**
Balance at beginning of period	**$ (141)**	$ (142)
Total gains and settlements	**24**	1
Balance at end of period	**$ (117)**	$ (141)

QUANTITATIVE INFORMATION ABOUT UNOBSERVABLE INPUTS

The following tables include quantitative information about the Duke Energy Registrants' derivatives classified as Level 3.

	December 31, 2019				
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**	**Weighted Average Range**
Duke Energy Ohio					
FTRs	**$ 4**	RTO auction pricing	FTR price – per MWh	**$ 0.59 – $ 3.47**	**$ 2.07**
Duke Energy Indiana					
FTRs	**11**	RTO auction pricing	FTR price – per MWh	**(0.66) – 9.24**	**1.15**
Piedmont					
Natural gas contracts	**(117)**	Discounted cash flow	Forward natural gas curves – price per MMBtu	**1.59 – 2.46**	**1.91**
Duke Energy					
Total Level 3 derivatives	**$ (102)**				

	December 31, 2018			
Investment Type	**Fair Value (in millions)**	**Valuation Technique**	**Unobservable Input**	**Range**
Duke Energy Ohio				
FTRs	$ 6	RTO auction pricing	FTR price – per MWh	$ 1.19 – $ 4.59
Duke Energy Indiana				
FTRs	22	RTO auction pricing	FTR price – per MWh	(2.07) – 8.27
Piedmont				
Natural gas contracts	(141)	Discounted cash flow	Forward natural gas curves – price per MMBtu	1.87 – 2.95
Duke Energy				
Total Level 3 derivatives	$ (113)			

DERF, DEPR and DEFR borrow amounts under credit facilities to buy these receivables. Borrowing availability from the credit facilities is limited to the amount of qualified receivables purchased. The sole source of funds to satisfy the related debt obligations is cash collections from the receivables. Amounts borrowed under the credit facilities are reflected on the Consolidated Balance Sheets as Long-Term Debt.

The most significant activity that impacts the economic performance of DERF, DEPR and DEFR are the decisions made to manage delinquent receivables. Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida are considered the primary beneficiaries and consolidate DERF, DEPR and DEFR, respectively, as they make those decisions.

Receivables Financing – CRC

CRC is a bankruptcy remote, special purpose entity indirectly owned by Duke Energy. On a revolving basis, CRC buys certain accounts receivable arising from the sale of electricity, natural gas and related services from Duke Energy Ohio and Duke Energy Indiana. CRC borrows amounts under a credit facility to buy the receivables from Duke Energy Ohio and Duke Energy Indiana. Borrowing availability from the credit facility is limited to the amount of qualified receivables sold to CRC. The sole source of funds to satisfy the related debt obligation is cash collections from the receivables. Amounts borrowed under the credit facility are reflected on Duke Energy's Consolidated Balance Sheets as Long-Term Debt.

The proceeds Duke Energy Ohio and Duke Energy Indiana receive from the sale of receivables to CRC are approximately 75% cash and 25% in the form of a subordinated note from CRC. The subordinated note is a retained interest in the receivables sold. Depending on collection experience, additional equity infusions to CRC may be required by Duke Energy to maintain a minimum equity balance of $3 million.

CRC is considered a VIE because (i) equity capitalization is insufficient to support its operations, (ii) power to direct the activities that most significantly impact the economic performance of the entity is not held by the equity holder and (iii) deficiencies in net worth of CRC are funded by Duke Energy. The most significant activities that impact the economic performance of CRC are decisions made to manage delinquent receivables. Duke Energy is considered the primary beneficiary and consolidates CRC as it makes these decisions. Neither Duke Energy Ohio nor Duke Energy Indiana consolidate CRC.

Receivables Financing – Credit Facilities

The following table summarizes the amounts and expiration dates of the credit facilities and associated restricted receivables described above.

	Duke Energy			
		Duke Energy Carolinas	Duke Energy Progress	Duke Energy Florida
(in millions)	**CRC**	**DERF**	**DEPR**	**DEFR**
Expiration date	February 2023	December 2022	February 2021	April 2021
Credit facility amount	$ 350	$ 475	$ 325	$ 250
Amounts borrowed at December 31, 2019	**350**	**474**	**325**	**250**
Amounts borrowed at December 31, 2018	325	450	300	225
Restricted Receivables at December 31, 2019	**522**	**642**	**489**	**336**
Restricted Receivables at December 31, 2018	564	699	547	357

Nuclear Asset-Recovery Bonds – Duke Energy Florida Project Finance, LLC (DEFPF)

DEFPF is a bankruptcy remote, wholly owned special purpose subsidiary of Duke Energy Florida. DEFPF was formed in 2016 for the sole purpose of issuing nuclear asset-recovery bonds to finance Duke Energy Florida's unrecovered regulatory asset related to Crystal River Unit 3.

In 2016, DEFPF issued senior secured bonds and used the proceeds to acquire nuclear asset-recovery property from Duke Energy Florida. The nuclear asset-recovery property acquired includes the right to impose, bill, collect and adjust a non-bypassable nuclear asset-recovery charge from all Duke Energy Florida retail customers until the bonds are paid in full and all financing costs have been recovered. The nuclear asset-recovery bonds are secured by the nuclear asset-recovery property and cash collections from the nuclear asset-recovery charges are the sole source of funds to satisfy the debt obligation. The bondholders have no recourse to Duke Energy Florida.

DEFPF is considered a VIE primarily because the equity capitalization is insufficient to support its operations. Duke Energy Florida has the power to direct the significant activities of the VIE as described above and therefore Duke Energy Florida is considered the primary beneficiary and consolidates DEFPF.

The following table summarizes the impact of DEFPF on Duke Energy Florida's Consolidated Balance Sheets.

	December 31,	
(in millions)	**2019**	**2018**
Receivables of VIEs	**$ 5**	$ 5
Regulatory Assets: Current	**52**	52
Current Assets: Other	**39**	39
Other Noncurrent Assets: Regulatory assets	**989**	1,041
Current Liabilities: Other	**10**	10
Current maturities of long-term debt	**54**	53
Long-Term Debt	**1,057**	1,111

Commercial Renewables

Certain of Duke Energy's renewable energy facilities are VIEs due to Duke Energy issuing guarantees for debt service and operations and maintenance reserves in support of debt financings. Assets are restricted and cannot be pledged as collateral or sold to third parties without prior approval of debt holders. Additionally, Duke Energy has VIEs associated with tax equity arrangements entered into with third-party investors in order to finance the cost of renewable assets eligible for tax credits. The activities that most significantly impacted the economic performance of these renewable energy facilities were decisions associated with siting, negotiating PPAs and EPC agreements, and decisions associated with ongoing operations and maintenance-related activities. Duke Energy is considered the primary beneficiary and consolidates the entities as it is responsible for all of these decisions.

The table below presents material balances reported on Duke Energy's Consolidated Balance Sheets related to Commercial Renewables VIEs.

	December 31,	
(in millions)	**2019**	**2018**
Current Assets: Other	**$ 203**	$ 123
Property, Plant and Equipment: Cost	**5,747**	4,007
Accumulated depreciation and amortization	**(1,041)**	(698)
Other Noncurrent Assets: Other	**106**	261
Current maturities of long-term debt	**162**	174
Long-Term Debt	**1,541**	1,587
Other Noncurrent Liabilities: AROs	**127**	106
Other Noncurrent Liabilities: Other	**228**	212

NON-CONSOLIDATED VIEs

The following tables summarize the impact of non-consolidated VIEs on the Consolidated Balance Sheets.

	December 31, 2019					
	Duke Energy				Duke	Duke
(in millions)	Pipeline Investments	Commercial Renewables	Other VIEs[a]	Total	Energy Ohio	Energy Indiana
Receivables from affiliated companies	$ —	$ (1)	$ —	$ (1)	$ 64	$ 77
Investments in equity method unconsolidated affiliates	1,179	300	—	1,479	—	—
Total assets	$ 1,179	$ 299	$ —	$ 1,478	$ 64	$ 77
Taxes accrued	(1)	—	—	(1)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	59	—	—	59	—	—
Other noncurrent liabilities	—	—	11	11	—	—
Total liabilities	$ 58	$ —	$ 15	$ 73	$ —	$ —
Net assets (liabilities)	$ 1,121	$ 299	$ (15)	$ 1,405	$ 64	$ 77

(a) Duke Energy holds a 50% equity interest in Pioneer. As of December 31, 2018, Pioneer was considered a VIE due to having insufficient equity to finance its own activities without subordinated financial support. In October 2019, Pioneer closed on a private placement debt offering that gave Pioneer sufficient equity to finance its own activities and, therefore, is no longer considered a VIE. Duke Energy's investment in Pioneer was $57 million at December 31, 2019.

	December 31, 2018					
	Duke Energy				Duke	Duke
(in millions)	Pipeline Investments	Commercial Renewables	Other VIEs	Total	Energy Ohio	Energy Indiana
Receivables from affiliated companies	$ —	$ —	$ —	$ —	$ 93	$ 118
Investments in equity method unconsolidated affiliates	822	190	48	1,060	—	—
Total assets	$ 822	$ 190	$ 48	$ 1,060	$ 93	$ 118
Taxes accrued	(1)	—	—	(1)	—	—
Other current liabilities	—	—	4	4	—	—
Deferred income taxes	21	—	—	21	—	—
Other noncurrent liabilities	—	—	12	12	—	—
Total liabilities	$ 20	$ —	$ 16	$ 36	$ —	$ —
Net assets	$ 802	$ 190	$ 32	$ 1,024	$ 93	$ 118

The Duke Energy Registrants are not aware of any situations where the maximum exposure to loss significantly exceeds the carrying values shown above except for the PPA with OVEC, which is discussed below, and various guarantees, including Duke Energy's guarantee agreement to support its share of the ACP revolving credit facility. Duke Energy's maximum exposure to loss under the terms of the guarantee is $827 million, which represents 47% of the outstanding borrowings under the credit facility as of December 31, 2019. For more information on various guarantees, refer to Note 8.

Pipeline Investments

Duke Energy has investments in various joint ventures with pipeline projects currently under construction. These entities are considered VIEs due to having insufficient equity to finance their own activities without subordinated financial support. Duke Energy does not have the power to direct the activities that most significantly impact the economic performance, the obligation to absorb losses or the right to receive benefits of these VIEs and therefore does not consolidate these entities.

Duke Energy has investments in various joint ventures with pipeline projects currently under construction. These entities are considered VIEs due to having insufficient equity to finance their own activities without subordinated financial support. Duke Energy does not have the power to direct the activities that most significantly impact the economic performance, the obligation to absorb losses or the right to receive benefits of these VIEs and therefore does not consolidate these entities.

The table below presents Duke Energy's ownership interest and investment balances in these joint ventures.

		VIE Investment Amount (in millions)	
Entity Name	**Ownership Interest**	**December 31, 2019**	**December 31, 2018**
ACP[a]	47%	**$ 1,179**	$ 797
Constitution[b]	24%	**—**	25
Total		**$ 1,179**	$ 822

(a) Duke Energy evaluated this investment for impairment as of December 31, 2019, and 2018, and determined that fair value approximated carrying value and therefore no impairment was necessary.

(b) During the years ended December 31, 2019, and 2018, Duke Energy recorded an OTTI of $25 million and $55 million, respectively, related to Constitution within Equity in earnings of unconsolidated affiliates on Duke Energy's Consolidated Statements of Income. The current year charge resulted in the full write-down of Duke Energy's investment in Constitution. See Notes 4 and 13 for additional information.

Commercial Renewables

Duke Energy has investments in various renewable energy project entities. Some of these entities are VIEs due to Duke Energy issuing guarantees for debt service and operations and maintenance reserves in support of debt financings. Duke Energy does not consolidate these VIEs because power to direct and control key activities is shared jointly by Duke Energy and other owners. In 2019, Duke Energy acquired a majority ownership in a portfolio of distributed fuel cell projects from Bloom Energy Corporation. Duke Energy is not the primary beneficiary of the assets within the portfolio and does not consolidate the assets in the portfolio.

OVEC

Duke Energy Ohio’s 9% ownership interest in OVEC is considered a non-consolidated VIE due to OVEC having insufficient equity to finance its activities without subordinated financial support. The activities that most significantly impact OVEC's economic performance include fuel strategy and supply activities and decisions associated with ongoing operations and maintenance-related activities. Duke Energy Ohio does not have the unilateral power to direct these activities, and therefore, does not consolidate OVEC.

As a counterparty to an Inter-Company Power Agreement (ICPA), Duke Energy Ohio has a contractual arrangement to receive entitlements to capacity and energy from OVEC’s power plants through June 2040 commensurate with its power participation ratio, which is equivalent to Duke Energy Ohio's ownership interest. Costs, including fuel, operating expenses, fixed costs, debt amortization and interest expense, are allocated to counterparties to the ICPA based on their power participation ratio. The value of the ICPA is subject to variability due to fluctuation in power prices and changes in OVEC's cost of business. On March 31, 2018, FES, a subsidiary of FirstEnergy Corp. and an ICPA counterparty with a power participation ratio of 4.85%, filed for Chapter 11 bankruptcy, which could increase costs allocated to the counterparties. On July 31, 2018, the bankruptcy court rejected the FES ICPA, which means OVEC is an unsecured creditor in the FES bankruptcy proceeding. Duke Energy Ohio cannot predict the impact of the bankruptcy filing on its OVEC interests. In addition, certain proposed environmental rulemaking could result in future increased OVEC cost allocations. See Note 4 for additional information.

CRC

See discussion under Consolidated VIEs for additional information related to CRC.

Amounts included in Receivables from affiliated companies in the above table for Duke Energy Ohio and Duke Energy Indiana reflect their retained interest in receivables sold to CRC. These subordinated notes held by Duke Energy Ohio and Duke Energy Indiana are stated at fair value. Carrying values of retained interests are determined by allocating carrying value of the receivables between assets sold and interests retained based on relative fair value. The allocated bases of the subordinated notes are not materially different than their face value because (i) the receivables generally turnover in less than two months, (ii) credit losses are reasonably predictable due to the broad customer base and lack of significant concentration and (iii) the equity in CRC is subordinate to all retained interests and thus would absorb losses first. The hypothetical effect on fair value of the retained interests assuming both a 10% and a 20% unfavorable variation in credit losses or discount rates is not material due to the short turnover of receivables and historically low credit loss history. Interest accrues to Duke Energy Ohio and Duke Energy Indiana on the retained interests using the acceptable yield method. This method generally approximates the stated rate on the notes since the allocated basis and the face value are nearly equivalent. An impairment charge is recorded against the carrying value of both retained interests and purchased beneficial interest whenever it is determined that an OTTI has occurred.

Key assumptions used in estimating fair value are detailed in the following table.

	Duke Energy Ohio		Duke Energy Indiana	
	2019	**2018**	**2019**	**2018**
Anticipated credit loss ratio	**0.6%**	0.5%	**0.3%**	0.3%
Discount rate	**3.3%**	3.0%	**3.3%**	3.0%
Receivable turnover rate	**13.4%**	13.5%	**11.5%**	11.0%

The following table shows the gross and net receivables sold.

	Duke Energy Ohio		Duke Energy Indiana	
	December 31,		December 31,	
(in millions)	**2019**	**2018**	**2019**	**2018**
Receivables sold	**$ 253**	$ 269	**$ 307**	$ 336
Less: Retained interests	**64**	93	**77**	118
Net receivables sold	**$ 189**	$ 176	**$ 230**	$ 218

The following table shows sales and cash flows related to receivables sold.

	Duke Energy Ohio			Duke Energy Indiana		
	Years Ended December 31,			Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**	**2019**	**2018**	**2017**
Sales						
Receivables sold	**$ 1,979**	$ 1,987	$ 1,879	**$ 2,837**	$ 2,842	$ 2,711
Loss recognized on sale	**14**	13	10	**17**	16	12
Cash flows						
Cash proceeds from receivables sold	**1,993**	1,967	1,865	**2,860**	2,815	2,694
Collection fees received	**1**	1	1	**1**	1	1
Return received on retained interests	**6**	6	3	**9**	9	7

Cash flows from sales of receivables are reflected within Cash Flows From Operating Activities on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Cash Flows.

Collection fees received in connection with servicing transferred accounts receivable are included in Operation, maintenance and other on Duke Energy Ohio's and Duke Energy Indiana's Consolidated Statements of Operations and Comprehensive Income. The loss recognized on sales of receivables is calculated monthly by multiplying receivables sold during the month by the required discount. The required discount is derived monthly utilizing a three-year weighted average formula that considers charge-off history, late charge history and turnover history on the sold receivables, as well as a component for the time value of money. The discount rate, or component for the time value of money, is the prior month-end LIBOR plus a fixed rate of 1.00%.

18. VARIABLE INTEREST ENTITIES

A VIE is an entity that is evaluated for consolidation using more than a simple analysis of voting control. The analysis to determine whether an entity is a VIE considers contracts with an entity, credit support for an entity, the adequacy of the equity investment of an entity and the relationship of voting power to the amount of equity invested in an entity. This analysis is performed either upon the creation of a legal entity or upon the occurrence of an event requiring reevaluation, such as a significant change in an entity's assets or activities. A qualitative analysis of control determines the party that consolidates a VIE. This assessment is based on (i) what party has the power to direct the activities of the VIE that most significantly impact its economic performance and (ii) what party has rights to receive benefits or is obligated to absorb losses that could potentially be significant to the VIE. The analysis of the party that consolidates a VIE is a continual reassessment.

CONSOLIDATED VIEs

The obligations of the consolidated VIEs discussed in the following paragraphs are nonrecourse to the Duke Energy Registrants. The registrants have no requirement to provide liquidity to, purchase assets of or guarantee performance of these VIEs unless noted in the following paragraphs.

No financial support was provided to any of the consolidated VIEs during the years ended December 31, 2019, 2018, and 2017, or is expected to be provided in the future, that was not previously contractually required.

Receivables Financing – DERF/DEPR/DEFR

DERF, DEPR and DEFR are bankruptcy remote, special purpose subsidiaries of Duke Energy Carolinas, Duke Energy Progress and Duke Energy Florida, respectively. DERF, DEPR and DEFR are wholly owned LLCs with separate legal existence from their parent companies, and their assets are not generally available to creditors of their parent companies. On a revolving basis, DERF, DEPR and DEFR buy certain accounts receivable arising from the sale of electricity and related services from their parent companies.

19. REVENUE

Duke Energy recognizes revenue consistent with amounts billed under tariff offerings or at contractually agreed upon rates based on actual physical delivery of electric or natural gas service, including estimated volumes delivered when billings have not yet occurred. As such, the majority of Duke Energy's revenues have fixed pricing based on the contractual terms of the published tariffs, with variability in expected cash flows attributable to the customer's volumetric demand and ultimate quantities of energy or natural gas supplied and used during the billing period. The stand-alone selling price of related sales are designed to support recovery of prudently incurred costs and an appropriate return on invested assets and are primarily governed by published tariff rates or contractual agreements approved by relevant regulatory bodies. As described in Note 1, certain excise taxes and franchise fees levied by state or local governments are required to be paid even if not collected from the customer. These taxes are recognized on a gross basis as part of revenues. Duke Energy elects to account for all other taxes net of revenues.

Performance obligations are satisfied over time as energy or natural gas is delivered and consumed with billings generally occurring monthly and related payments due within 30 days, depending on regulatory requirements. In no event does the timing between payment and delivery of the goods and services exceed one year. Using this output method for revenue recognition provides a faithful depiction of the transfer of electric and natural gas service as customers obtain control of the commodity and benefit from its use at delivery. Additionally, Duke Energy has an enforceable right to consideration for energy or natural gas delivered at any discrete point in time and will recognize revenue at an amount that reflects the consideration to which Duke Energy is entitled for the energy or natural gas delivered.

As described above, the majority of Duke Energy's tariff revenues are at-will and, as such, related contracts with customers have an expected duration of one year or less and will not have future performance obligations for disclosure. Additionally, other long-term revenue streams, including wholesale contracts, generally provide services that are part of a single performance obligation, the delivery of electricity or natural gas. As such, other than material fixed consideration under long-term contracts, related disclosures for future performance obligations are also not applicable.

Duke Energy earns substantially all of its revenues through its reportable segments, Electric Utilities and Infrastructure, Gas Utilities and Infrastructure and Commercial Renewables.

Electric Utilities and Infrastructure

Electric Utilities and Infrastructure earns the majority of its revenues through retail and wholesale electric service through the generation, transmission, distribution and sale of electricity. Duke Energy generally provides retail and wholesale electric service customers with their full electric load requirements or with supplemental load requirements when the customer has other sources of electricity.

Retail electric service is generally marketed throughout Duke Energy's electric service territory through standard service offers. The standard service offers are through tariffs determined by regulators in Duke Energy's regulated service territory. Each tariff, which is assigned to customers based on customer class, has multiple components such as an energy charge, a demand charge, a basic facilities charge and applicable riders. Duke Energy considers each of these components to be aggregated into a single performance obligation for providing electric service, or in the case of distribution only customers in Duke Energy Ohio, for delivering electricity. Electricity is considered a single performance obligation satisfied over time consistent with the series guidance and is provided and consumed over the billing period, generally one month. Retail electric service is typically provided to at-will customers who can cancel service at any time, without a substantive penalty. Additionally, Duke Energy adheres to applicable regulatory requirements in each jurisdiction to ensure the collectability of amounts billed and appropriate mitigating procedures are followed when necessary. As such, revenue from contracts with customers for such contracts is equivalent to the electricity supplied and billed in that period (including unbilled estimates).

Wholesale electric service is generally provided under long-term contracts using cost-based pricing. FERC regulates costs that may be recovered from customers and the amount of return companies are permitted to earn. Wholesale contracts include both energy and demand charges. For full requirements contracts, Duke Energy considers both charges as a single performance obligation for providing integrated electric service. For contracts where energy and demand charges are considered separate performance obligations, energy and demand are each a distinct performance obligation under the series guidance and are satisfied as energy is delivered and stand-ready service is provided on a monthly basis. This service represents consumption over the billing period and revenue is recognized consistent with billings and unbilled estimates, which generally occur monthly. Contractual amounts owed are typically trued up annually based upon incurred costs in accordance with FERC published filings and the specific customer's actual peak demand. Estimates of variable consideration related to potential additional billings or refunds owed are updated quarterly.

The majority of wholesale revenues are full requirements contracts where the customers purchase the substantial majority of their energy needs and do not have a fixed quantity of contractually required energy or capacity. As such, related forecasted revenues are considered optional purchases. Supplemental requirements contracts that include contracted blocks of energy and capacity at contractually fixed prices have the following estimated remaining performance obligations:

	Remaining Performance Obligations						
(in millions)	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Progress Energy	$ 121	$ 92	$ 87	$ 44	$ 45	$ 58	$ 447
Duke Energy Progress	8	8	8	8	8	—	40
Duke Energy Florida	113	84	79	36	37	58	407
Duke Energy Indiana	10	5	—	—	—	—	15

Revenues for block sales are recognized monthly as energy is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates.

Gas Utilities and Infrastructure

Gas Utilities and Infrastructure earns its revenue through retail and wholesale natural gas service through the transportation, distribution and sale of natural gas. Duke Energy generally provides retail and wholesale natural gas service customers with all natural gas load requirements. Additionally, while natural gas can be stored, substantially all natural gas provided by Duke Energy is consumed by customers simultaneously with receipt of delivery.

Retail natural gas service is marketed throughout Duke Energy's natural gas service territory using published tariff rates. The tariff rates are established by regulators in Duke Energy's service territories. Each tariff, which is assigned to customers based on customer class, have multiple components, such as a commodity charge, demand charge, customer or monthly charge and transportation costs. Duke Energy considers each of these components to be aggregated into a single performance obligation for providing natural gas service. For contracts where Duke Energy provides all of the customer's natural gas needs, the delivery of natural gas is considered a single performance obligation satisfied over time, and revenue is recognized monthly based on billings and unbilled estimates as service is provided and the commodity is consumed over the billing period. Additionally, natural gas service is typically at-will and customers can cancel service at any time, without a substantive penalty. Duke Energy also adheres to applicable regulatory requirements to ensure the collectability of amounts billed and receivable and appropriate mitigating procedures are followed when necessary.

Certain long-term individually negotiated contracts exist to provide natural gas service. These contracts are regulated and approved by state commissions. The negotiated contracts have multiple components, including a natural gas and a demand charge, similar to retail natural gas contracts. Duke Energy considers each of these components to be a single performance obligation for providing natural gas service. This service represents consumption over the billing period, generally one month.

Fixed capacity payments under long-term contracts for the Gas Utilities and Infrastructure segment include minimum margin contracts and supply arrangements with municipalities and power generation facilities. Revenues for related sales are recognized monthly as natural gas is delivered and stand-ready service is provided, consistent with invoiced amounts and unbilled estimates. Estimated remaining performance obligations are as follows:

	Remaining Performance Obligations						
(in millions)	**2020**	**2021**	**2022**	**2023**	**2024**	**Thereafter**	**Total**
Piedmont	$ 69	$ 64	$ 64	$ 61	$ 58	$ 372	$ 688

Commercial Renewables

Commercial Renewables earns the majority of its revenues through long-term PPAs and generally sells all of its wind and solar facility output, electricity and RECs to customers. The majority of these PPAs have historically been accounted for as leases. For PPAs that are not accounted for as leases, the delivery of electricity and the delivery of RECs are considered separate performance obligations.

The delivery of electricity is a performance obligation satisfied over time and represents generation and consumption of the electricity over the billing period, generally one month. The delivery of RECs is a performance obligation satisfied at a point in time and represents delivery of each REC generated by the wind or solar facility. The majority of self-generated RECs are bundled with energy in Duke Energy's contracts and, as such, related revenues are recognized as energy is generated and delivered as that pattern is consistent with Duke Energy's performance. Commercial Renewables recognizes revenue based on the energy generated and billed for the period, generally one month, at contractual rates (including unbilled estimates) according to the invoice practical expedient. Amounts are typically due within 30 days of invoice.

Commercial Renewables also earns revenues from installation of distributed solar generation resources, which is primarily composed of EPC projects to deliver functioning solar power systems, generally completed within two to 12 months from commencement of construction. The installation of distributed solar generation resources is a performance obligation that is satisfied over time. Revenue from fixed-price EPC contracts is recognized using the input method as work is performed based on the estimated ratio of incurred costs to estimated total costs.

Other

The remainder of Duke Energy's operations is presented as Other, which does not include material revenues from contracts with customers.

Disaggregated Revenues

For the Electric and Gas Utility and Infrastructure segments, revenue by customer class is most meaningful to Duke Energy as each respective customer class collectively represents unique customer expectations of service, generally has different energy and demand requirements, and operates under tailored, regulatory approved pricing structures. Additionally, each customer class is impacted differently by weather and a variety of economic factors including the level of population growth, economic investment, employment levels, and regulatory activities in each of Duke Energy's jurisdictions. As such, analyzing revenues disaggregated by customer class allows Duke Energy to understand the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers. For the Commercial Renewables segment, the majority of revenues from contracts with customers are from selling all of the unit-contingent output at contractually defined pricing under long-term PPAs with consistent expectations regarding the timing and certainty of cash flows. Disaggregated revenues are presented as follows:

(in millions) By market or type of customer	Year Ended December 31, 2019 Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electric Utilities and Infrastructure								
Residential	$ 9,863	$ 3,044	$ 4,998	$ 2,144	$ 2,854	$ 733	$ 1,087	$ —
General	6,431	2,244	2,935	1,368	1,567	451	802	—
Industrial	3,071	1,215	934	675	259	147	774	—
Wholesale	2,212	462	1,468	1,281	187	46	235	—
Other revenues	770	276	548	317	231	80	89	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 22,347	$ 7,241	$ 10,883	$ 5,785	$ 5,098	$ 1,457	$ 2,987	$ —
Gas Utilities and Infrastructure								
Residential	$ 976	$ —	$ —	$ —	$ —	$ 315	$ —	$ 661
Commercial	508	—	—	—	—	130	—	378
Industrial	141	—	—	—	—	19	—	122
Power Generation	—	—	—	—	—	—	—	51
Other revenues	129	—	—	—	—	19	—	110
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 1,754	$ —	$ —	$ —	$ —	$ 483	$ —	$ 1,322
Commercial Renewables								
Revenue from contracts with customers	$ 223	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Other								
Revenue from contracts with customers	$ 24	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Total revenue from contracts with customers	$ 24,348	$ 7,241	$ 10,883	$ 5,785	$ 5,098	$ 1,940	$ 2,987	$ 1,322
Other revenue sources[a]	$ 731	$ 154	$ 319	$ 172	$ 133	$ —	$ 17	$ 59
Total revenues	$ 25,079	$ 7,395	$ 11,202	$ 5,957	$ 5,231	$ 1,940	$ 3,004	$ 1,381

(a) Other revenue sources include revenues from leases, derivatives and alternative revenue programs that are not considered revenues from contracts with customers. Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over or under collection of related revenues.

(in millions) By market or type of customer	Year Ended December 31, 2018 Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Electric Utilities and Infrastructure								
Residential	$ 9,587	$ 2,981	$ 4,785	$ 2,019	$ 2,766	$ 743	$ 1,076	$ —
General	6,127	2,119	2,809	1,280	1,529	422	778	—
Industrial	2,974	1,180	904	642	262	131	760	—
Wholesale	2,324	508	1,462	1,303	159	57	298	—
Other revenues	717	320	502	320	182	73	91	—
Total Electric Utilities and Infrastructure revenue from contracts with customers	$ 21,729	$ 7,108	$ 10,462	$ 5,564	$ 4,898	$ 1,426	$ 3,003	$ —
Gas Utilities and Infrastructure								
Residential	$ 1,000	$ —	$ —	$ —	$ —	$ 331	$ —	$ 669
Commercial	514	—	—	—	—	135	—	378
Industrial	147	—	—	—	—	18	—	128
Power Generation	—	—	—	—	—	—	—	54
Other revenues	139	—	—	—	—	19	—	120
Total Gas Utilities and Infrastructure revenue from contracts with customers	$ 1,800	$ —	$ —	$ —	$ —	$ 503	$ —	$ 1,349
Commercial Renewables								
Revenue from contracts with customers	$ 209	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Other								
Revenue from contracts with customers	$ 19	$ —	$ —	$ —	$ —	$ 1	$ —	$ —
Total revenue from contracts with customers	$ 23,757	$ 7,108	$ 10,462	$ 5,564	$ 4,898	$ 1,930	$ 3,003	$ 1,349
Other revenue sources[a]	$ 764	$ 192	$ 266	$ 135	$ 123	$ 27	$ 56	$ 26
Total revenues	$ 24,521	$ 7,300	$ 10,728	$ 5,699	$ 5,021	$ 1,957	$ 3,059	$ 1,375

(a) Other revenue sources include revenues from leases, derivatives and alternative revenue programs that are not considered revenues from contracts with customers. Alternative revenue programs in certain jurisdictions include regulatory mechanisms that periodically adjust for over or under collection of related revenues.

IMPACT OF WEATHER AND THE TIMING OF BILLING PERIODS

Revenues and costs are influenced by seasonal weather patterns. Peak sales of electricity occur during the summer and winter months, which results in higher revenue and cash flows during these periods. By contrast, lower sales of electricity occur during the spring and fall, allowing for scheduled plant maintenance. Residential and general service customers are more impacted by weather than industrial customers. Estimated weather impacts are based on actual current period weather compared to normal weather conditions. Normal weather conditions are defined as the long-term average of actual historical weather conditions. Heating degree days measure the variation in weather based on the extent the average daily temperature falls below a base temperature. Cooling degree days measure the variation in weather based on the extent the average daily temperature rises above the base temperature. Each degree of temperature below the base temperature counts as one heating degree day and each degree of temperature above the base temperature counts as one cooling degree day.

The estimated impact of weather on earnings for Electric Utilities and Infrastructure is based on the temperature variances from a normal condition and customers' historic usage patterns. The methodology used to estimate the impact of weather does not consider all variables that may impact customer response to weather conditions, such as humidity in the summer or wind chill in the winter. The precision of this estimate may also be impacted by applying long-term weather trends to shorter-term periods.

Gas Utilities and Infrastructure's costs and revenues are influenced by seasonal patterns due to peak natural gas sales occurring during the winter months as a result of space heating requirements. Residential customers are the most impacted by weather. There are certain regulatory mechanisms for the North Carolina, South Carolina, Tennessee, Ohio and Kentucky service territories that normalize the margins collected from certain customer classes during the winter. In North Carolina, rate design provides protection from both weather and other usage variations such as conservation, while South Carolina, Tennessee and Kentucky revenues are adjusted solely based on weather. Ohio primarily employs a fixed charge each month regardless of the season and usage.

UNBILLED REVENUE

Unbilled revenues are recognized by applying customer billing rates to the estimated volumes of energy or natural gas delivered but not yet billed. Unbilled revenues can vary significantly from period to period as a result of seasonality, weather, customer usage patterns, customer mix, average price in effect for customer classes, timing of rendering customer bills and meter reading schedules, and the impact of weather normalization or margin decoupling mechanisms.

Unbilled revenues are included within Receivables and Receivables of VIEs on the Consolidated Balance Sheets as shown in the following table.

	December 31,	
(in millions)	**2019**	**2018**
Duke Energy	**$ 843**	$ 896
Duke Energy Carolinas	**298**	313
Progress Energy	**217**	244
Duke Energy Progress	**122**	148
Duke Energy Florida	**95**	96
Duke Energy Ohio	**1**	2
Duke Energy Indiana	**16**	23
Piedmont	**78**	73

Additionally, Duke Energy Ohio and Duke Energy Indiana sell, on a revolving basis, nearly all of their retail accounts receivable, including receivables for unbilled revenues, to an affiliate, CRC and account for the transfers of receivables as sales. Accordingly, the receivables sold are not reflected on the Consolidated Balance Sheets of Duke Energy Ohio and Duke Energy Indiana. See Note 18 for further information. These receivables for unbilled revenues are shown in the table below.

(in millions)	December 31, 2019	2018
Duke Energy Ohio	$ **82**	$ 86
Duke Energy Indiana	**115**	128

20. STOCKHOLDERS' EQUITY

Basic EPS is computed by dividing net income available to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the weighted average number of common shares outstanding during the period. Diluted EPS is computed by dividing net income available to Duke Energy common stockholders, as adjusted for distributed and undistributed earnings allocated to participating securities, by the diluted weighted average number of common shares outstanding during the period. Diluted EPS reflects the potential dilution that could occur if securities or other agreements to issue common stock, such as stock options and equity forward sale agreements, were exercised or settled. Duke Energy's participating securities are RSUs that are entitled to dividends declared on Duke Energy common stock during the RSUs vesting periods. Dividends declared on preferred stock are recorded on the Consolidated Statements of Operations as a reduction of net income to arrive at net income available to Duke Energy common stockholders. Dividends accumulated on preferred stock are a reduction to net income used in the calculation of basic and diluted EPS.

The following table presents Duke Energy's basic and diluted EPS calculations, the weighted average number of common shares outstanding and common and preferred share dividends declared.

(in millions, except per share amounts)	Years Ended December 31, 2019	2018	2017
Income from continuing operations available to Duke Energy common stockholders excluding impact of participating securities and including accumulated preferred stock dividends	$ **3,694**	$ 2,642	$ 3,059
Weighted average common shares outstanding – basic and diluted	**729**	708	700
EPS from continuing operations available to Duke Energy common stockholders			
Basic and diluted	$ **5.07**	$ 3.73	$ 4.37
Potentially dilutive items excluded from the calculation[a]	**2**	2	2
Dividends declared per common share	$ **3.75**	$ 3.64	$ 3.49
Dividends declared on Series A preferred stock per depositary share	$ **1.03**	$ —	$ —

(a) Performance stock awards were not included in the dilutive securities calculation because the performance measures related to the awards had not been met.

Common Stock

In February 2018, Duke Energy filed a prospectus supplement and executed an Equity Distribution Agreement (EDA) under which it may sell up to $1 billion of its common stock through an ATM offering program, including an equity forward sales component. Under the terms of the EDA, Duke Energy was allowed to issue and sell shares of common stock. The existing ATM offering program expired in September 2019.

In June 2018, Duke Energy marketed two separate tranches, each for 1.3 million shares, of common stock through equity forward transactions under the ATM program. In December 2018, Duke Energy physically settled these equity forwards by delivering 2.6 million shares of common stock in exchange for net proceeds of approximately $195 million.

In March 2018, Duke Energy marketed an equity offering of 21.3 million shares of common stock through an Underwriting Agreement. In connection with the offering, Duke Energy entered into equity forward sale agreements. The equity forwards required Duke Energy to either physically settle the transactions by issuing 21.3 million shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreements, or net settle in whole or in part through the delivery or receipt of cash or shares. In June 2018, Duke Energy physically settled one-half of the equity forwards by delivering approximately 10.6 million shares of common stock in exchange for net cash proceeds of approximately $781 million. In December 2018, Duke Energy physically settled the remaining equity forward by delivering 10.6 million shares of common stock in exchange for net cash proceeds of approximately $766 million.

In March and April 2019, Duke Energy marketed two separate tranches, each for 1.1 million shares, of common stock through equity forward transactions under the ATM program. The first tranche had an initial forward price of $89.83 per share and the second tranche had an initial forward price of $88.82 per share. In May and June 2019, a third tranche of 1.6 million shares of common stock was marketed and had an initial forward price of $86.23. The equity forwards required Duke Energy to either physically settle the transaction by issuing shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreements or net settle in whole or in part through the delivery or receipt of cash or shares. The settlement alternative was at Duke Energy's election. In December 2019, Duke Energy physically settled the equity forwards by delivering 3.8 million shares of common stock in exchange for net cash proceeds of approximately $331 million.

In November 2019, Duke Energy filed a prospectus supplement and executed an EDA under which it may sell up to $1.5 billion of its common stock through a new ATM offering program, including an equity forward sales component. Under the terms of the EDA, Duke Energy may issue and sell shares of common stock through September 2022.

In November 2019, Duke Energy marketed an equity offering of 28.75 million shares of common stock through an Underwriting Agreement. In connection with the offering, Duke Energy entered into equity forward sales agreements with an initial forward price of $85.99 per share. The equity forward sales agreements require Duke Energy to either physically settle the transaction by issuing shares in exchange for net proceeds at the then-applicable forward sale price specified by the agreement, or net settle in whole or in part through the delivery or receipt of cash or shares. The settlement alternatives are at Duke Energy's election. Settlement of the forward sales agreements are expected to occur on or prior to December 31, 2020. If Duke Energy had elected to net share settle these contracts as of December 31, 2019, Duke Energy would have been required to deliver 1.6 million shares.

For the years ended December 31, 2019, and 2018, Duke Energy issued 1.8 million and 2.2 million shares, respectively, through its DRIP with an increase in additional paid-in capital of approximately $160 million and $174 million, respectively.

Preferred Stock

On March 29, 2019, Duke Energy completed the issuance of 40 million depositary shares, each representing 1/1,000th share of its Series A Cumulative Redeemable Perpetual Preferred Stock, at a price of $25 per depositary share. The transaction resulted in net proceeds of $973 million after issuance costs with proceeds used for general corporate purposes and to reduce short-term debt. The preferred stock has a $25 liquidation preference per depositary share and earns dividends on a cumulative basis at a rate of 5.75% per annum. Dividends are payable quarterly in arrears on the 16th day of March, June, September and December, and began on June 16, 2019.

The Series A Preferred Stock has no maturity or mandatory redemption date, is not redeemable at the option of the holders and includes separate call options. The first call option allows Duke Energy to call the Series A Preferred Stock at a redemption price of $25.50 per depositary share prior to June 15, 2024, in whole but not in part, at any time within 120 days after a ratings event where a rating agency amends, clarifies or changes the criteria it uses to assign equity credit for securities such as the preferred stock. The second call option allows Duke Energy to call the preferred stock, in whole or in part, at any time, on or after June 15, 2024, at a redemption price of $25 per depositary share. Duke Energy is also required to redeem all accumulated and unpaid dividends if either call option is exercised.

On September 12, 2019, Duke Energy completed the issuance of 1 million shares of its Series B Fixed-Rate Reset Cumulative Redeemable Perpetual Preferred Stock, at a price of $1,000 per share. The transaction resulted in net proceeds of $989 million after issuance costs with proceeds being used to pay down short-term debt, repay at maturity $500 million senior notes due September 2019, and for general corporate purposes. The preferred stock has a $1,000 liquidation preference per share and earns dividends on a cumulative basis at an initial rate of 4.875% per annum. Dividends are payable semiannually in arrears on the 16th day of March and September, beginning on March 16, 2020. On September 16, 2024, the First Call Date, and any fifth anniversary of the First Call Date (each a Reset Date), the dividend rate will reset based on the then current five-year U.S. treasury rate plus a spread of 3.388%.

The Series B Preferred Stock has no maturity or mandatory redemption date, is not redeemable at the option of the holders and includes separate call options. The first call option allows Duke Energy to call the Series B Preferred Stock at a redemption price of $1,020 per share, in whole but not in part, at any time within 120 days after a ratings event. The second call option allows Duke Energy to call the preferred stock, in whole or in part, on the First Call Date or any subsequent Reset Date at a redemption price in cash equal to $1,000 per share. Duke Energy is also required to redeem all accumulated and unpaid dividends if either call option is exercised.

Dividends issued on its Series A and Series B Preferred Stock are subject to approval by the Board of Directors. However, the deferral of dividend payments on the preferred stock prohibits the declaration of common stock dividends.

The Series A and Series B Preferred Stock rank, with respect to dividends and distributions upon liquidation or dissolution:

- senior to Common Stock and to each other class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is expressly made subordinated to the Series A and Series B Preferred Stock;
- on a parity with any class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is not expressly made senior or subordinated to the Series A or Series B Preferred Stock;
- junior to any class or series of capital stock established after the original issue date of the Series A and Series B Preferred Stock that is expressly made senior to the Series A or Series B Preferred Stock;
- junior to all existing and future indebtedness (including indebtedness outstanding under Duke Energy's credit facilities, unsecured senior notes, junior subordinated debentures and commercial paper) and other liabilities with respect to assets available to satisfy claims against Duke Energy; and
- structurally subordinated to existing and future indebtedness and other liabilities of Duke Energy's subsidiaries and future preferred stock of subsidiaries.

Holders of Series A and Series B Preferred Stock have no voting rights with respect to matters that generally require the approval of voting stockholders. The limited voting rights of holders of Series A and Series B Preferred Stock include the right to vote as a single class, respectively, on certain matters that may affect the preference or special rights of the preferred stock, except in the instance that Duke Energy elects to defer the payment of dividends for a total of six quarterly full dividend periods for Series A Preferred Stock or three semiannual full dividend periods for Series B Preferred Stock. If dividends are deferred for a cumulative total of six quarterly full dividend periods for Series A Preferred Stock or three semiannual full dividend periods for Series B Preferred Stock, whether or not for consecutive dividend periods, holders of the respective preferred stock have the right to elect two additional Board members to the Board of Directors.

21. SEVERANCE

During 2018, Duke Energy reviewed its operations and identified opportunities for improvement to better serve its customers. This operational review included the company's workforce strategy and staffing levels to ensure the company was staffed with the right skillsets and number of teammates to execute the long-term vision for Duke Energy. As such, Duke Energy extended voluntary and involuntary severance benefits to certain employees in specific areas as a part of workforce planning and digital transformation efforts.

The following table presents the direct and allocated severance and related charges accrued for approximately 140 employees in 2019, 1,900 employees in 2018 and 100 employees in 2017 by the Duke Energy Registrants within Operation, maintenance and other on the Consolidated Statements of Operations.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Year Ended December 31, 2019	**$ 16**	**$ 8**	**$ 6**	**$ 3**	**$ 3**	**$ —**	**$ 1**	**$ 1**
Year Ended December 31, 2018	187	102	69	52	17	6	7	2
Year Ended December 31, 2017	15	2	2	1	1	—	1	9

The table below presents the severance liability for past and ongoing severance plans including the plans described above.

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Balance at December 31, 2018	$ 205	$ 100	$ 51	$ 41	$ 9	$ 2	$ 2	$ —
Provision/Adjustments	**24**	**4**	**11**	**2**	**10**	**1**	**1**	**—**
Cash Reductions	**(188)**	**(93)**	**(49)**	**(37)**	**(12)**	**(2)**	**(1)**	**—**
Balance at December 31, 2019	**$ 41**	**$ 11**	**$ 13**	**$ 6**	**$ 7**	**$ 1**	**$ 2**	**$ —**

22. STOCK-BASED COMPENSATION

The Duke Energy Corporation 2015 Long-Term Incentive Plan (the 2015 Plan) provides for the grant of stock-based compensation awards to employees and outside directors. The 2015 Plan reserves 10 million shares of common stock for issuance. Duke Energy has historically issued new shares upon exercising or vesting of share-based awards. However, Duke Energy may use a combination of new share issuances and open market repurchases for share-based awards that are exercised or vest in the future. Duke Energy has not determined with certainty the amount of such new share issuances or open market repurchases.

The following table summarizes the total expense recognized by the Duke Energy Registrants, net of tax, for stock-based compensation.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
Duke Energy	**$ 65**	$ 56	$ 43
Duke Energy Carolinas	**24**	20	15
Progress Energy	**24**	21	16
Duke Energy Progress	**15**	13	10
Duke Energy Florida	**9**	8	6
Duke Energy Ohio	**5**	4	3
Duke Energy Indiana	**6**	5	4
Piedmont	**3**	3	3

Duke Energy's pretax stock-based compensation costs, the tax benefit associated with stock-based compensation expense and stock-based compensation costs capitalized are included in the following table.

	Years Ended December 31,		
(in millions)	**2019**	**2018**	**2017**
RSU awards	**$ 44**	$ 43	$ 41
Performance awards	**45**	35	27
Pretax stock-based compensation cost	**$ 89**	$ 78	$ 68
Stock-based compensation costs capitalized	**5**	5	4
Stock-based compensation expense	**$ 84**	$ 73	$ 64
Tax benefit associated with stock-based compensation expense	**$ 19**	$ 17	$ 25

RESTRICTED STOCK UNIT AWARDS

RSU awards generally vest over periods from immediate to three years. Fair value amounts are based on the market price of Duke Energy's common stock on the grant date. The following table includes information related to RSU awards.

	Years Ended December 31,		
	2019	**2018**	**2017**
Shares granted (in thousands)	**571**	649	583
Fair value (in millions)	**$ 51**	$ 49	$ 47

The following table summarizes information about RSU awards outstanding.

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2018	1,153	$ 77
Granted	**571**	**89**
Vested	**(631)**	**77**
Forfeited	**(83)**	**82**
Outstanding at December 31, 2019	**1,010**	**83**
RSU awards expected to vest	**951**	**83**

The total grant date fair value of shares vested during the years ended December 31, 2019, 2018 and 2017, was $49 million, $43 million and $42 million, respectively. At December 31, 2019, Duke Energy had $30 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 23 months. Prior to Duke Energy's acquisition of Piedmont, Piedmont had an incentive compensation plan that had a series of three-year performance and RSU awards for eligible officers and other participants. The 2016-2018 performance award cycle was approved subsequent to the Agreement and Plan of Merger between Duke Energy and Piedmont and was converted into a Duke Energy RSU award at the consummation of the acquisition.

PERFORMANCE AWARDS

Stock-based performance awards generally vest after three years if performance targets are met. The actual number of shares issued will range from zero to 200% of target shares, depending on the level of performance achieved.

Performance awards contain performance conditions and a market condition. The performance conditions are based on Duke Energy's cumulative adjusted EPS and total incident case rate (total incident case rate is one of our key employee safety metrics). The market condition is based on TSR of Duke Energy relative to a predefined peer group.

Relative TSR is valued using a path-dependent model that incorporates expected relative TSR into the fair value determination of Duke Energy's performance-based share awards. The model uses three-year historical volatilities and correlations for all companies in the predefined peer group, including Duke Energy, to simulate Duke Energy's relative TSR as of the end of the performance period. For each simulation, Duke Energy's relative TSR associated with the simulated stock price at the end of the performance period plus expected dividends within the period results in a value per share for the award portfolio. The average of these simulations is the expected portfolio value per share. Actual life to date results of Duke Energy's relative TSR for each grant are incorporated within the model. For performance awards granted in 2019, the model used a risk-free interest rate of 2.5%, which reflects the yield on three-year Treasury bonds as of the grant date, and an expected volatility of 14.8% based on Duke Energy's historical volatility over three years using daily stock prices.

The following table includes information related to stock-based performance awards.

	Years Ended December 31,		
	2019	**2018**	**2017**
Shares granted assuming target performance (in thousands)	**320**	372	461
Fair value (in millions)	**$ 27**	$ 27	$ 37

The following table summarizes information about stock-based performance awards outstanding and assumes payout at the target level.

	Shares (in thousands)	**Weighted Average Grant Date Fair Value (per share)**
Outstanding at December 31, 2018	1,117	$ 77
Granted	**320**	**86**
Vested	**(310)**	**75**
Forfeited	**(18)**	**81**
Outstanding at December 31, 2019	**1,109**	**80**
Stock-based performance awards expected to vest	**1,080**	**80**

The total grant date fair value of shares vested during the years ended December 31, 2019, and 2018, was $23 million and $13 million, respectively. No performance awards vested during the year ended December 31, 2017. At December 31, 2019, Duke Energy had $27 million of unrecognized compensation cost, which is expected to be recognized over a weighted average period of 22 months.

OTHER FAIR VALUE DISCLOSURES

The fair value and book value of long-term debt, including current maturities, is summarized in the following table. Estimates determined are not necessarily indicative of amounts that could have been settled in current markets. Fair value of long-term debt uses Level 2 measurements.

	December 31, 2019		December 31, 2018	
(in millions)	**Book Value**	**Fair Value**	**Book Value**	**Fair Value**
Duke Energy[(a)]	**$ 58,126**	**$ 63,062**	$ 54,529	$ 54,534
Duke Energy Carolinas	**11,900**	**13,516**	10,939	11,471
Progress Energy	**19,634**	**22,291**	18,911	19,885
Duke Energy Progress	**9,058**	**9,934**	8,204	8,300
Duke Energy Florida	**7,987**	**9,131**	7,321	7,742
Duke Energy Ohio	**2,619**	**2,964**	2,165	2,239
Duke Energy Indiana	**4,057**	**4,800**	3,782	4,158
Piedmont	**2,384**	**2,642**	2,138	2,180

(a) Book value of long-term debt includes $1.5 billion as of December 31, 2019, and $1.6 billion as of December 31, 2018, of unamortized debt discount and premium, net in purchase accounting adjustments related to the mergers with Progress Energy and Piedmont that are excluded from fair value of long-term debt.

At both December 31, 2019, and December 31, 2018, fair value of cash and cash equivalents, accounts and notes receivable, accounts payable, notes payable and commercial paper, and nonrecourse notes payable of VIEs are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

23. EMPLOYEE BENEFIT PLANS

DEFINED BENEFIT RETIREMENT PLANS

Duke Energy and certain subsidiaries maintain, and the Subsidiary Registrants participate in, qualified, non-contributory defined benefit retirement plans. The Duke Energy plans cover most employees using a cash balance formula. Under a cash balance formula, a plan participant accumulates a retirement benefit consisting of pay credits based upon a percentage of current eligible earnings, age or age and years of service and interest credits. Certain employees are eligible for benefits that use a final average earnings formula. Under these final average earnings formulas, a plan participant accumulates a retirement benefit equal to the sum of percentages of their (i) highest three-year, four-year, or five-year average earnings, (ii) highest three-year, four-year, or five-year average earnings in excess of covered compensation per year of participation (maximum of 35 years) or (iii) highest three-year average earnings times years of participation in excess of 35 years. Duke Energy also maintains, and the Subsidiary Registrants participate in, non-qualified, non-contributory defined benefit retirement plans that cover certain executives. The qualified and non-qualified, non-contributory defined benefit plans are closed to new participants.

Duke Energy approved plan amendments to restructure its qualified non-contributory defined benefit retirement plans, effective January 1, 2018. The restructuring involved (i) the spin-off of the majority of inactive participants from two plans into a separate inactive plan and (ii) the merger of the active participant portions of such plans, along with a pension plan acquired as part of the Piedmont transaction, into a single active plan. Benefits offered to the plan participants remain unchanged except that the Piedmont plan's final average earnings formula was frozen as of December 31, 2017, and affected participants were moved into the active plan's cash balance formula. Actuarial gains and losses associated with the Inactive Plan will be amortized over the remaining life expectancy of the inactive participants. The longer amortization period lowered Duke Energy's 2018 pretax qualified pension plan expense by approximately $33 million.

Duke Energy uses a December 31 measurement date for its defined benefit retirement plan assets and obligations.

As a result of the application of settlement accounting due to total lump-sum benefit payments exceeding the settlement threshold (defined as the sum of the service cost and interest cost on projected benefit obligation components of net periodic pension costs) for one of its qualified pension plans, Duke Energy recognized settlement charges of $94 million, primarily as a regulatory asset within Other Noncurrent Assets on the Consolidated Balance Sheets as of December 31, 2019 (an immaterial amount was recorded in Other income and expenses, net within the Consolidated Statement of Operations).

Settlement charges recognized by the Subsidiary Registrants as of December 31, 2019, which represent amounts allocated by Duke Energy for employees of the Subsidiary Registrants and allocated charges for their proportionate share of settlement charges for employees of Duke Energy's shared services affiliate, were $53 million for Duke Energy Carolinas, $26 million for Progress Energy, $20 million for Duke Energy Progress, $6 million for Duke Energy Florida, $4 million for Duke Energy Indiana, $2 million for Duke Energy Ohio and $8 million for Piedmont.

The settlement charges reflect the recognition of a pro-rata portion of previously unrecognized actuarial losses, equal to the percentage of reduction in the projected benefit obligation resulting from total lump-sum benefit payments as of December 31, 2019. Settlement charges recognized as a regulatory asset within Other Noncurrent Assets on the Consolidated Balance Sheets are amortized over the average remaining service period for participants in the plan. Amortization of settlement charges is disclosed in the tables below as a component of net periodic pension costs.

Net periodic benefit costs disclosed in the tables below represent the cost of the respective benefit plan for the periods presented prior to capitalization of amounts reflected as Net property, plant and equipment, on the Consolidated Balance Sheets. Only the service cost component of net periodic benefit costs is eligible to be capitalized. The remaining non-capitalized portions of net periodic benefit costs are classified as either: (1) service cost, which is recorded in Operations, maintenance and other on the Consolidated Statements of Operations; or as (2) components of non-service cost, which is recorded in Other income and expenses, net, on the Consolidated Statements of Operations. Amounts presented in the tables below for the Subsidiary Registrants represent the amounts of pension and other post-retirement benefit cost allocated by Duke Energy for employees of the Subsidiary Registrants. Additionally, the Consolidated Statements of Operations of the Subsidiary Registrants also include allocated net periodic benefit costs for their proportionate share of pension and post-retirement benefit cost for employees of Duke Energy's shared services affiliate that provide support to the Subsidiary Registrants. However, in the tables below, these amounts are only presented within the Duke Energy column (except for amortization of settlement charges). These allocated amounts are included in the governance and shared service costs discussed in Note 14.

Duke Energy's policy is to fund amounts on an actuarial basis to provide assets sufficient to meet benefit payments to be paid to plan participants. Duke Energy does not anticipate making any contributions in 2020. The following table includes information related to the Duke Energy Registrants' contributions to its qualified defined benefit pension plans.

	Duke	Duke	Duke	Duke	Duke

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Contributions Made:								
2019	$ 77	$ 7	$ 57	$ 4	$ 53	$ 2	$ 2	$ 1
2018	141	46	45	25	20	—	8	—
2017	19	—	—	—	—	4	—	11

QUALIFIED PENSION PLANS

Components of Net Periodic Pension Costs

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 158	$ 49	$ 46	$ 26	$ 20	$ 4	$ 9	$ 5
Interest cost on projected benefit obligation	317	75	100	45	54	18	26	10
Expected return on plan assets	(567)	(147)	(178)	(88)	(89)	(28)	(43)	(22)
Amortization of actuarial loss	108	24	39	15	24	4	8	8
Amortization of prior service credit	(32)	(8)	(3)	(2)	(1)	—	(2)	(9)
Amortization of settlement charges	6	2	1	1	—	2	—	—
Net periodic pension costs[a][b]	$ (10)	$ (5)	$ 5	$ (3)	$ 8	$ —	$ (2)	$ (8)

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 182	$ 58	$ 51	$ 29	$ 22	$ 5	$ 11	$ 7
Interest cost on projected benefit obligation	299	72	94	43	50	17	23	11
Expected return on plan assets	(559)	(147)	(178)	(85)	(91)	(28)	(42)	(22)
Amortization of actuarial loss	132	29	44	21	23	5	10	11
Amortization of prior service credit	(32)	(8)	(3)	(2)	(1)	—	(2)	(10)
Net periodic pension costs[a][b]	$ 22	$ 4	$ 8	$ 6	$ 3	$ (1)	$ —	$ (3)

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 159	$ 48	$ 45	$ 26	$ 19	$ 4	$ 9	$ 10
Interest cost on projected benefit obligation	328	79	100	47	53	18	26	14
Expected return on plan assets	(545)	(142)	(167)	(82)	(85)	(27)	(42)	(24)
Amortization of actuarial loss	146	31	52	23	29	5	12	11
Amortization of prior service credit	(24)	(8)	(3)	(2)	(1)	(1)	(2)	(2)
Settlement charge	12	—	—	—	—	—	—	12
Other	8	2	2	1	1	—	1	1
Net periodic pension costs[a][b]	$ 84	$ 10	$ 29	$ 13	$ 16	$ (1)	$ 4	$ 22

(a) Duke Energy amounts exclude $4 million, $5 million and $7 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $3 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net increase (decrease)	**$ (212)**	**$ (156)**	**$ (79)**	**$ (59)**	**$ (20)**	**$ 12**	**$ 22**	**$ —**
Accumulated other comprehensive loss (income)								
Deferred income tax expense (benefit)	**$ 20**	**—**	**1**	**—**	**(1)**	**—**	**—**	**—**
Amortization of prior year service credit	**1**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Amortization of prior year actuarial losses	**(15)**	**—**	**(2)**	**—**	**3**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ 6**	**$ —**	**$ (1)**	**$ —**	**$ 2**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Regulatory assets, net increase	$ 298	$ 170	$ 40	$ 31	$ 9	$ 10	$ 30	$ 8
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ (2)	$ —	$ 1	$ —	$ —	$ —	$ —	$ —
Prior year service credit arising during the year	1	—	—	—	—	—	—	—
Amortization of prior year actuarial losses	10	—	(4)	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ 9	$ —	$ (3)	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Net Amount Recognized

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 7,869	$ 1,954	$ 2,433	$ 1,125	$ 1,295	$ 435	$ 618	$ 264
Service cost	150	47	43	25	18	4	8	5
Interest cost	317	75	100	45	54	18	26	10
Actuarial loss	716	101	223	87	135	54	87	33
Transfers	—	11	—	—	—	—	—	—
Benefits paid	(731)	(265)	(191)	(112)	(78)	(30)	(46)	(20)
Obligation at measurement date	$ 8,321	$ 1,923	$ 2,608	$ 1,170	$ 1,424	$ 481	$ 693	$ 292
Accumulated Benefit Obligation at measurement date	$ 8,262	$ 1,923	$ 2,578	$ 1,170	$ 1,392	$ 471	$ 686	$ 292
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 8,233	$ 2,168	$ 2,606	$ 1,268	$ 1,322	$ 405	$ 611	$ 305
Employer contributions	77	7	57	4	53	2	2	1
Actual return on plan assets	1,331	342	426	204	218	66	100	49
Benefits paid	(731)	(265)	(191)	(112)	(78)	(30)	(46)	(20)
Transfers	—	11	—	—	—	—	—	—
Plan assets at measurement date	$ 8,910	$ 2,263	$ 2,898	$ 1,364	$ 1,515	$ 443	$ 667	$ 335
Funded status of plan	$ 589	$ 340	$ 290	$ 194	$ 91	$ (38)	$ (26)	$ 43

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Obligation at prior measurement date	$ 8,448	$ 2,029	$ 2,637	$ 1,211	$ 1,410	$ 479	$ 669	$ 313
Service cost	174	56	49	28	21	5	10	7
Interest cost	299	72	94	43	50	17	23	11
Actuarial gain	(485)	(44)	(204)	(87)	(114)	(29)	(29)	(18)
Transfers	—	—	—	—	—	—	—	(16)
Benefits paid	(567)	(159)	(143)	(70)	(72)	(37)	(55)	(33)
Obligation at measurement date	$ 7,869	$ 1,954	$ 2,433	$ 1,125	$ 1,295	$ 435	$ 618	$ 264
Accumulated Benefit Obligation at measurement date	$ 7,818	$ 1,954	$ 2,404	$ 1,125	$ 1,265	$ 425	$ 614	$ 264
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 9,003	$ 2,372	$ 2,814	$ 1,366	$ 1,429	$ 458	$ 684	$ 368
Employer contributions	141	46	45	25	20	—	8	—
Actual return on plan assets	(344)	(91)	(110)	(53)	(55)	(16)	(26)	(14)
Benefits paid	(567)	(159)	(143)	(70)	(72)	(37)	(55)	(33)
Transfers	—	—	—	—	—	—	—	(16)
Plan assets at measurement date	$ 8,233	$ 2,168	$ 2,606	$ 1,268	$ 1,322	$ 405	$ 611	$ 305
Funded status of plan	$ 364	$ 214	$ 173	$ 143	$ 27	$ (30)	$ (7)	$ 41

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Prefunded pension[a]	$ 621	$ 340	$ 322	$ 194	$ 123	$ 38	$ 57	$ 43
Noncurrent pension liability[b]	$ 32	$ —	$ 32	$ —	$ 32	$ 76	$ 83	$ —
Net asset (liability) recognized	$ 589	$ 340	$ 290	$ 194	$ 91	$ (38)	$ (26)	$ 43
Regulatory assets	$ 1,972	$ 420	$ 717	$ 313	$ 404	$ 112	$ 204	$ 81
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (23)	$ —	$ (1)	$ —	$ (1)	$ —	$ —	$ —
Prior service credit	(3)	—	—	—	—	—	—	—
Net actuarial loss	111	—	3	—	3	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 85	$ —	$ 2	$ —	$ 2	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 135	$ 29	$ 43	$ 19	$ 24	$ 7	$ 10	$ 9
Unrecognized prior service credit	(32)	(8)	(3)	(2)	(1)	(1)	(2)	(9)

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Prefunded pension[a]	$ 433	$ 214	$ 242	$ 143	$ 96	$ 24	$ 39	$ 41
Noncurrent pension liability[b]	$ 69	$ —	$ 69	$ —	$ 69	$ 54	$ 46	$ —
Net asset recognized	$ 364	$ 214	$ 173	$ 143	$ 27	$ (30)	$ (7)	$ 41
Regulatory assets	$ 2,184	$ 576	$ 796	$ 372	$ 424	$ 100	$ 182	$ 81
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (43)	$ —	$ (2)	$ —	$ —	$ —	$ —	$ —
Prior service credit	(4)	—	—	—	—	—	—	—
Net actuarial loss	126	—	5	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive loss	$ 79	$ —	$ 3	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension costs in the next year								
Unrecognized net actuarial loss	$ 97	$ 22	$ 37	$ 13	$ 24	$ 3	$ 5	$ 7
Unrecognized prior service credit	$ (32)	$ (8)	$ (3)	$ (2)	$ (1)	$ —	$ (2)	$ (9)

(a) Included in Other within Other Noncurrent Assets on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

Information for Plans with Accumulated Benefit Obligation in Excess of Plan Assets

	December 31, 2019	
(in millions)	Duke Energy Ohio	Duke Energy Indiana
Projected benefit obligation	$ 155	$ 260
Accumulated benefit obligation	146	252
Fair value of plan assets	79	177

	December 31, 2018				
(in millions)	Duke Energy	Progress Energy	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana
Projected benefit obligation	$ 679	$ 679	$ 679	$ 123	$ 203
Accumulated benefit obligation	651	651	651	115	199
Fair value of plan assets	610	610	610	69	159

Assumptions Used for Pension Benefits Accounting

The discount rate used to determine the current year pension obligation and following year's pension expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

The average remaining service period for participants in active plans and life expectancy of participants in inactive plans is 12 years for Duke Energy, Duke Energy Carolinas, Progress Energy and Duke Energy Florida, 13 years for Duke Energy Progress, Duke Energy Indiana and Duke Energy Ohio, and 9 years for Piedmont.

The following tables present the assumptions or range of assumptions used for pension benefit accounting.

	December 31,		
	2019	2018	2017
Benefit Obligations			
Discount rate	**3.30%**	4.30%	3.60%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	3.50% – 4.00%
Net Periodic Benefit Cost			
Discount rate	**4.30%**	3.60%	4.10%
Salary increase	**3.50% – 4.00%**	3.50% – 4.00%	4.00% – 4.50%
Expected long-term rate of return on plan assets	**6.85%**	6.50%	6.50% – 6.75%

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2020	$ 643	$ 167	$ 169	$ 89	$ 79	$ 37	$ 50	$ 28
2021	653	171	178	95	82	37	50	24
2022	649	177	176	92	84	37	49	22
2023	649	174	182	95	86	36	48	21
2024	638	168	184	96	87	35	48	20
2025-2029	2,851	714	871	419	448	156	220	87

NON-QUALIFIED PENSION PLANS

The accumulated benefit obligation, which equals the projected benefit obligation for non-qualified pension plans, was $318 million for Duke Energy, $15 million for Duke Energy Carolinas, $110 million for Progress Energy, $32 million for Duke Energy Progress, $45 million for Duke Energy Florida, $4 million for Duke Energy Ohio, $3 million for Duke Energy Indiana and $4 million for Piedmont as of December 31, 2019.

Employer contributions, which equal benefits paid for non-qualified pension plans, were $25 million for Duke Energy, $2 million for Duke Energy Carolinas, $9 million for Progress Energy, $3 million for Duke Energy Progress and $3 million for Duke Energy Florida for the year ended December 31, 2019. Employer contributions were not material for Duke Energy Ohio, Duke Energy Indiana or Piedmont for the year ended December 31, 2019.

Net periodic pension costs for non-qualified pension plans were not material for the years ended December 31, 2019, 2018 or 2017.

OTHER POST-RETIREMENT BENEFIT PLANS

Duke Energy provides, and the Subsidiary Registrants participate in, some health care and life insurance benefits for retired employees on a contributory and non-contributory basis. Employees are eligible for these benefits if they have met age and service requirements at retirement, as defined in the plans. The health care benefits include medical, dental and prescription drug coverage and are subject to certain limitations, such as deductibles and copayments.

Duke Energy did not make any pre-funding contributions to its other post-retirement benefit plans during the years ended December 31, 2019, 2018 or 2017.

Components of Net Periodic Other Post-Retirement Benefit Costs

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 4	$ 1	$ 1	$ —	$ 1	$ —	$ 1	$ —
Interest cost on accumulated post-retirement benefit obligation	30	7	12	7	5	1	3	1
Expected return on plan assets	(12)	(7)	—	—	—	—	—	(1)
Amortization of actuarial loss	4	2	1	—	1	—	4	—
Amortization of prior service credit	(19)	(5)	(8)	(1)	(7)	(1)	(1)	(2)
Net periodic post-retirement benefit costs (a)(b)	$ 7	$ (2)	$ 6	$ 6	$ —	$ —	$ 7	$ (2)

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 6	$ 1	$ 1	$ —	$ 1	$ 1	$ 1	$ 1
Interest cost on accumulated post-retirement benefit obligation	28	7	12	6	6	1	3	1
Expected return on plan assets	(13)	(8)	—	—	—	—	—	(2)
Amortization of actuarial loss	6	3	1	1	—	—	4	—
Amortization of prior service credit	(19)	(5)	(8)	(1)	(7)	(1)	(1)	(2)
Net periodic post-retirement benefit costs(a)(b)	$ 8	$ (2)	$ 6	$ 6	$ —	$ 1	$ 7	$ (2)

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Service cost	$ 4	$ 1	$ —	$ —	$ —	$ —	$ —	$ 1
Interest cost on accumulated post-retirement benefit obligation	34	8	13	7	6	1	3	1
Expected return on plan assets	(14)	(8)	—	—	—	—	(1)	(2)
Amortization of actuarial loss (gain)	10	(2)	21	12	9	(2)	(1)	1
Amortization of prior service credit	(115)	(10)	(84)	(54)	(30)	—	(1)	—
Curtailment credit(c)	(30)	(4)	(16)	—	(16)	(2)	(2)	—
Net periodic post-retirement benefit costs(a)(b)	$ (111)	$ (15)	$ (66)	$ (35)	$ (31)	$ (3)	$ (2)	$ 1

Duke Energy amounts exclude $6 million, $7 million and $7 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(b) Duke Energy Ohio amounts exclude $2 million, $2 million and $2 million for the years ended December 2019, 2018 and 2017, respectively, of regulatory asset amortization resulting from purchase accounting adjustments associated with Duke Energy's merger with Cinergy in April 2006.

(c) Curtailment credit resulted from a reduction in average future service of plan participants due to a plan amendment.

Amounts Recognized in Accumulated Other Comprehensive Income and Regulatory Assets and Liabilities

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Regulatory assets, net increase (decrease)	**$ (127)**	**$ —**	**$ (127)**	**$ (82)**	**$ (45)**	**$ —**	**$ (5)**	**$ —**
Regulatory liabilities, net increase (decrease)	**$ (152)**	**$ 1**	**$ (149)**	**$ (93)**	**$ (56)**	**$ (1)**	**$ (4)**	**$ 3**
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**
Amortization of prior year actuarial gain	**(4)**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Net amount recognized in accumulated other comprehensive income	**$ (4)**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**	**$ —**

	Year Ended December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Regulatory assets, net increase (decrease)	$ 137	$ —	$ 133	$ 84	$ 49	$ —	$ (5)	$ 4
Regulatory liabilities, net increase (decrease)	$ 154	$ (6)	$ 149	$ 93	$ 56	$ 2	$ 3	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax benefit	$ (1)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amortization of prior year prior service credit	1	—	—	—	—	—	—	—
Net amount recognized in accumulated other comprehensive income	$ —	$ —	$ —	$ —	$ —	$ —	$ —	$ —

Reconciliation of Funded Status to Accrued Other Post-Retirement Benefit Costs

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 728	$ 174	$ 303	$ 166	$ 137	$ 29	$ 67	$ 30
Service cost	4	1	1	—	1	—	1	—
Interest cost	30	7	12	7	5	1	3	1
Plan participants' contributions	16	3	6	3	2	1	2	—
Actuarial losses	28	9	13	9	5	1	2	—
Transfers	—	—	—	—	—	—	—	—
Benefits paid	(83)	(19)	(32)	(17)	(15)	(3)	(11)	(1)
Accumulated post-retirement benefit obligation at measurement date	$ 723	$ 175	$ 303	$ 168	$ 135	$ 29	$ 64	$ 30
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 195	$ 115	$ —	$ —	$ —	$ 8	$ 5	$ 29
Actual return on plan assets	32	20	(1)	—	—	1	—	6
Benefits paid	(83)	(19)	(32)	(17)	(15)	(3)	(11)	(1)
Employer contributions	60	11	26	13	13	2	9	—
Plan participants' contributions	16	3	6	3	2	1	2	—
Plan assets at measurement date	$ 220	$ 130	$ (1)	$ (1)	$ —	$ 9	$ 5	$ 34
Funded status of plan	$ (503)	$ (45)	$ (304)	$ (169)	$ (135)	$ (20)	$ (59)	$ 4

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Change in Projected Benefit Obligation								
Accumulated post-retirement benefit obligation at prior measurement date	$ 813	$ 189	$ 342	$ 184	$ 156	$ 30	$ 78	$ 32
Service cost	6	1	1	—	1	1	1	1
Interest cost	28	7	12	6	6	1	3	1
Plan participants' contributions	18	3	6	4	3	1	2	—
Actuarial losses (gains)	(51)	(8)	(23)	(9)	(13)	(2)	(5)	(1)
Transfers	—	—	—	—	—	—	—	(1)
Benefits paid	(86)	(18)	(35)	(19)	(16)	(2)	(12)	(2)
Accumulated post-retirement benefit obligation at measurement date	$ 728	$ 174	$ 303	$ 166	$ 137	$ 29	$ 67	$ 30
Change in Fair Value of Plan Assets								
Plan assets at prior measurement date	$ 225	$ 133	$ —	$ —	$ —	$ 7	$ 11	$ 31
Actual return on plan assets	(8)	(5)	—	—	—	—	—	(1)
Benefits paid	(86)	(18)	(35)	(19)	(16)	(2)	(12)	(2)
Employer contributions (reimbursements)	46	2	29	15	13	2	4	1
Plan participants' contributions	18	3	6	4	3	1	2	—
Plan assets at measurement date	$ 195	$ 115	$ —	$ —	$ —	$ 8	$ 5	$ 29
Funded status of plan	$ (533)	$ (59)	$ (303)	$ (166)	$ (137)	$ (21)	$ (62)	$ (1)

Amounts Recognized in the Consolidated Balance Sheets

	December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current post-retirement liability[a]	$ 9	$ —	$ 5	$ 3	$ 2	$ 1	$ —	$ —
Noncurrent post-retirement liability[b]	494	45	299	166	133	19	59	(4)
Total accrued post-retirement liability	$ 503	$ 45	$ 304	$ 169	$ 135	$ 20	$ 59	$ (4)
Regulatory assets	$ 135	$ —	$ 135	$ 82	$ 53	$ —	$ 36	$ —
Regulatory liabilities	$ 149	$ 39	$ —	$ —	$ —	$ 17	$ 63	$ 3
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(13)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (12)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss	$ 5	$ 3	$ 1	$ —	$ 1	$ —	$ —	$ —
Unrecognized prior service credit	(14)	(4)	(3)	(1)	(2)	(1)	(1)	(2)

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current post-retirement liability[a]	$ 8	$ —	$ 5	$ 3	$ 2	$ 2	$ —	$ —
Noncurrent post-retirement liability[b]	525	59	298	163	135	19	62	1
Total accrued post-retirement liability	$ 533	$ 59	$ 303	$ 166	$ 137	$ 21	$ 62	$ 1
Regulatory assets	$ 262	$ —	$ 262	$ 164	$ 98	$ —	$ 41	$ —
Regulatory liabilities	$ 301	$ 38	$ 149	$ 93	$ 56	$ 18	$ 67	$ —
Accumulated other comprehensive (income) loss								
Deferred income tax expense	$ 3	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Prior service credit	(2)	—	—	—	—	—	—	—
Net actuarial gain	(9)	—	—	—	—	—	—	—
Net amounts recognized in accumulated other comprehensive income	$ (8)	$ —	$ —	$ —	$ —	$ —	$ —	$ —
Amounts to be recognized in net periodic pension expense in the next year								
Unrecognized net actuarial loss (gain)	$ 4	$ 2	$ 1	$ —	$ —	$ —	$ —	$ —
Unrecognized prior service credit	(19)	(5)	(7)	(1)	(6)	(1)	(1)	(2)

(a) Included in Other within Current Liabilities on the Consolidated Balance Sheets.
(b) Included in Accrued pension and other post-retirement benefit costs on the Consolidated Balance Sheets.

Assumptions Used for Other Post-Retirement Benefits Accounting

The discount rate used to determine the current year other post-retirement benefits obligation and following year's other post-retirement benefits expense is based on a bond selection-settlement portfolio approach. This approach develops a discount rate by selecting a portfolio of high quality corporate bonds that generate sufficient cash flow to provide for projected benefit payments of the plan. The selected bond portfolio is derived from a universe of non-callable corporate bonds rated Aa quality or higher. After the bond portfolio is selected, a single interest rate is determined that equates the present value of the plan's projected benefit payments discounted at this rate with the market value of the bonds selected.

The average remaining service period of active covered employees is eight years for Duke Energy and Duke Energy Carolinas, seven years for Progress Energy, Duke Energy Florida, and Duke Energy Ohio, and six years for Duke Energy Progress, Duke Energy Indiana, and Piedmont.

The following tables present the assumptions used for other post-retirement benefits accounting.

	December 31,		
	2019	**2018**	**2017**
Benefit Obligations			
Discount rate	**3.30%**	4.30%	3.60%
Net Periodic Benefit Cost			
Discount rate	**4.30%**	3.60%	4.10%
Expected long-term rate of return on plan assets	**6.85%**	6.50%	6.50%
Assumed tax rate	**23%**	35%	35%

Assumed Health Care Cost Trend Rate

	December 31,	
	2019	**2018**
Health care cost trend rate assumed for next year	**6.00%**	6.50%
Rate to which the cost trend is assumed to decline (the ultimate trend rate)	**4.75%**	4.75%
Year that rate reaches ultimate trend	**2026**	2024

Sensitivity to Changes in Assumed Health Care Cost Trend Rates

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
1-Percentage Point Increase								
Effect on total service and interest costs	$ 1	$ —	$ 1	$ 1	$ —	$ —	$ —	—
Effect on post-retirement benefit obligation	22	5	9	5	4	1	2	1
1-Percentage Point Decrease								
Effect on total service and interest costs	(1)	—	(1)	(1)	—	—	—	—
Effect on post-retirement benefit obligation	(20)	(5)	(8)	(4)	(4)	(1)	(2)	(1)

Expected Benefit Payments

(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Years ending December 31,								
2020	$ 76	$ 18	$ 29	$ 16	$ 13	$ 4	$ 8	$ 2
2021	70	17	28	15	13	3	7	2
2022	66	16	27	14	12	3	7	2
2023	63	15	25	14	12	3	6	2
2024	59	15	24	13	11	3	6	2
2025-2029	246	60	101	55	46	11	23	11

PLAN ASSETS

Description and Allocations

Duke Energy Master Retirement Trust

Assets for both the qualified pension and other post-retirement benefits are maintained in the Duke Energy Master Retirement Trust. Approximately 98% of the Duke Energy Master Retirement Trust assets were allocated to qualified pension plans and approximately 2% were allocated to other post-retirement plans (comprised of 401(h) accounts), as of December 31, 2019, and 2018. The investment objective of the Duke Energy Master Retirement Trust is to invest in a diverse portfolio of assets that is expected to generate positive surplus return over time (i.e. asset growth greater than liability growth) subject to a prudent level of portfolio risk, for the purpose of enhancing the security of benefits for plan participants.

As of December 31, 2019, Duke Energy assumes pension and other post-retirement plan assets will generate a long-term rate of return of 6.85%. The expected long-term rate of return was developed using a weighted average calculation of expected returns based primarily on future expected returns across asset classes considering the use of active asset managers, where applicable. The asset allocation targets were set after considering the investment objective and the risk profile. Equity securities are held for their higher expected returns. Debt securities are primarily held to hedge the qualified pension plan liability. Real assets, return seeking fixed income, hedge funds and other global securities are held for diversification. Investments within asset classes are diversified to achieve broad market participation and reduce the impact of individual managers or investments.

Effective January 1, 2019, the target asset allocation for the Duke Energy Retirement Master Trust is 58% liability hedging assets and 42% return-seeking assets. Duke Energy periodically reviews its asset allocation targets, and over time, as the funded status of the benefit plans increase, the level of asset risk relative to plan liabilities may be reduced to better manage Duke Energy's benefit plan liabilities and reduce funded status volatility.

The Duke Energy Master Retirement Trust is authorized to engage in the lending of certain plan assets. Securities lending is an investment management enhancement that utilizes certain existing securities of the Duke Energy Master Retirement Trust to earn additional income. Securities lending involves the loaning of securities to approved parties. In return for the loaned securities, the Duke Energy Master Retirement Trust receives collateral in the form of cash and securities as a safeguard against possible default of any borrower on the return of the loan under terms that permit the Duke Energy Master Retirement Trust to sell the securities. The Duke Energy Master Retirement Trust mitigates credit risk associated with securities lending arrangements by monitoring the fair value of the securities loaned, with additional collateral obtained or refunded as necessary. The fair value of securities on loan was approximately $351 million and $154 million at December 31, 2019, and 2018, respectively. Cash and securities obtained as collateral exceeded the fair value of the securities loaned at December 31, 2019, and 2018, respectively. Securities lending income earned by the Duke Energy Master Retirement Trust was immaterial for the years ended December 31, 2019, 2018 and 2017, respectively.

Qualified pension and other post-retirement benefits for the Subsidiary Registrants are derived from the Duke Energy Master Retirement Trust, as such, each are allocated their proportionate share of the assets discussed below.

The following table includes the target asset allocations by asset class at December 31, 2019, and the actual asset allocations for the Duke Energy Master Retirement Trust.

	Target Allocation	Actual Allocation at December 31, 2019	2018
U.S. equity securities	—%	**—%**	11%
Global equity securities	28%	**27%**	18%
Global private equity securities	1%	**1%**	2%
Debt securities	58%	**57%**	63%
Return seeking debt securities	4%	**5%**	—%
Hedge funds	3%	**3%**	2%
Real estate and cash	6%	**7%**	2%
Other global securities	—%	**—%**	2%
Total	100%	**100%**	100%

Other post-retirement assets

Duke Energy's other post-retirement assets are comprised of VEBA trusts and 401(h) accounts held within the Duke Energy Master Retirement Trust. Duke Energy's investment objective is to achieve sufficient returns, subject to a prudent level of portfolio risk, for the purpose of promoting the security of plan benefits for participants.

The following table presents target and actual asset allocations for the VEBA trusts at December 31, 2019.

	Target Allocation	Actual Allocation at December 31, 2019	2018
U.S. equity securities	33%	**35%**	43%
Non-U.S. equity securities	7%	**9%**	8%
Real estate	2%	**2%**	2%
Debt securities	45%	**37%**	40%
Cash	13%	**17%**	7%
Total	100%	**100%**	100%

Fair Value Measurements

Duke Energy classifies recurring and non-recurring fair value measurements based on the fair value hierarchy as discussed in Note 17.

Valuation methods of the primary fair value measurements disclosed below are as follows:

Investments in equity securities

Investments in equity securities are typically valued at the closing price in the principal active market as of the last business day of the reporting period. Principal active markets for equity prices include published exchanges such as NASDAQ and NYSE. Foreign equity prices are translated from their trading currency using the currency exchange rate in effect at the close of the principal active market. Prices have not been adjusted to reflect after-hours market activity. The majority of investments in equity securities are valued using Level 1 measurements. When the price of an institutional commingled fund is unpublished, it is not categorized in the fair value hierarchy, even though the funds are readily available at the fair value.

Investments in corporate debt securities and U.S. government securities

Most debt investments are valued based on a calculation using interest rate curves and credit spreads applied to the terms of the debt instrument (maturity and coupon interest rate) and consider the counterparty credit rating. Most debt valuations are Level 2 measurements. If the market for a particular fixed-income security is relatively inactive or illiquid, the measurement is Level 3. U.S. Treasury debt is typically Level 2.

Investments in short-term investment funds

Investments in short-term investment funds are valued at the net asset value of units held at year end and are readily redeemable at the measurement date. Investments in short-term investment funds with published prices are valued as Level 1. Investments in short-term investment funds with unpublished prices are valued as Level 2.

Investments in real estate limited partnerships

Investments in real estate limited partnerships are valued by the trustee at each valuation date (monthly). As part of the trustee's valuation process, properties are externally appraised generally on an annual basis, conducted by reputable, independent appraisal firms, and signed by appraisers that are members of the Appraisal Institute, with the professional designation MAI. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. There are three valuation techniques that can be used to value investments in real estate assets: the market, income or cost approach. The appropriateness of each valuation technique depends on the type of asset or business being valued. In addition, the trustee may cause additional appraisals to be performed as warranted by specific asset or market conditions. Property valuations and the salient valuation-sensitive assumptions of each direct investment property are reviewed by the trustee quarterly and values are adjusted if there has been a significant change in circumstances related to the investment property since the last valuation. Value adjustments for interim capital expenditures are only recognized to the extent that the valuation process acknowledges a corresponding increase in fair value. An independent firm is hired to review and approve quarterly direct real estate valuations. Key inputs and assumptions used to determine fair value includes among others, rental revenue and expense amounts and related revenue and expense growth rates, terminal capitalization rates and discount rates. Development investments are valued using cost incurred to date as a primary input until substantive progress is achieved in terms of mitigating construction and leasing risk at which point a discounted cash flow approach is more heavily weighted. Key inputs and assumptions in addition to those noted above used to determine the fair value of development investments include construction costs and the status of construction completion and leasing. Investments in real estate limited partnerships are valued at net asset value of units held at year end and are not readily redeemable at the measurement date. Investments in real estate limited partnerships are not categorized within the fair value hierarchy.

Duke Energy Master Retirement Trust

The following tables provide the fair value measurement amounts for the Duke Energy Master Retirement Trust qualified pension and other post-retirement assets.

	December 31, 2019				
(in millions)	**Total Fair Value**	**Level 1**	**Level 2**	**Level 3**	**Not Categorized[b]**
Equity securities	**$ 2,730**	**$ 2,712**	**$ —**	**$ —**	**$ 18**
Corporate debt securities	**3,999**	**—**	**3,999**	**—**	**—**
Short-term investment funds	**545**	**455**	**90**	**—**	**—**
Partnership interests	**104**	**—**	**—**	**—**	**104**
Hedge funds	**206**	**—**	**—**	**—**	**206**
Real estate limited partnerships	**—**	**—**	**—**	**—**	**—**
U.S. government securities	**1,231**	**—**	**1,231**	**—**	**—**
Guaranteed investment contracts	**11**	**—**	**—**	**11**	**—**
Governments bonds – foreign	**78**	**—**	**78**	**—**	**—**
Cash	**75**	**75**	**—**	**—**	**—**
Net pending transactions and other investments	**46**	**(43)**	**89**	**—**	**—**
Total assets[a]	**$ 9,025**	**$ 3,199**	**$ 5,487**	**$ 11**	**$ 328**

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 26%, 31%, 15%, 17%, 5%, 7%, and 4%, respectively, of the Duke Energy Master Retirement Trust at December 31, 2019. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

	December 31, 2018				
(in millions)	Total Fair Value	Level 1	Level 2	Level 3	Not Categorized[b]
Equity securities	$ 2,373	$ 1,751	$ —	$ —	$ 622
Corporate debt securities	4,054	—	4,054	—	—
Short-term investment funds	363	279	84	—	—
Partnership interests	120	—	—	—	120
Hedge funds	226	—	—	—	226
Real estate limited partnerships	144	—	—	—	144
U.S. government securities	961	—	961	—	—
Guaranteed investment contracts	27	—	—	27	—
Governments bonds – foreign	30	—	30	—	—
Cash	28	28	—	—	—
Net pending transactions and other investments	(2)	(6)	4	—	—
Total assets[a]	$ 8,324	$ 2,052	$ 5,133	$ 27	$ 1,112

(a) Duke Energy Carolinas, Progress Energy, Duke Energy Progress, Duke Energy Florida, Duke Energy Ohio, Duke Energy Indiana, and Piedmont were allocated approximately 27%, 31%, 15%, 16%, 5%, 7%, and 4%, respectively, of the Duke Energy Master Retirement Trust and Piedmont's Pension assets at December 31, 2018. Accordingly, all amounts included in the table above are allocable to the Subsidiary Registrants using these percentages.

(b) Certain investments that are measured at fair value using the net asset value per share practical expedient have not been categorized in the fair value hierarchy.

The following table provides a reconciliation of beginning and ending balances of Duke Energy Master Retirement Trust qualified pension and other post-retirement assets at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3).

(in millions)	2019	2018
Balance at January 1	**$ 27**	$ 28
Sales	**(18)**	(1)
Total gains and other, net	**2**	—
Transfer of Level 3 assets to other classifications	**—**	—
Balance at December 31	**$ 11**	$ 27

Other post-retirement assets

The following tables provide the fair value measurement amounts for VEBA trust assets.

	December 31, 2019	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	**$ 9**	**$ 9**
Real estate	**1**	**1**
Equity securities	**22**	**22**
Debt securities	**18**	**18**
Total assets	**$ 50**	**$ 50**

	December 31, 2018	
(in millions)	**Total Fair Value**	**Level 2**
Cash and cash equivalents	$ 3	**$ 3**
Real estate	1	**1**
Equity securities	25	**25**
Debt securities	20	**20**
Total assets	$ 49	$ 49

EMPLOYEE SAVINGS PLANS

Retirement Savings Plan

Duke Energy or its affiliates sponsor, and the Subsidiary Registrants participate in, employee savings plans that cover substantially all U.S. employees. Most employees participate in a matching contribution formula where Duke Energy provides a matching contribution generally equal to 100% of employee before-tax and Roth 401(k) contributions of up to 6% of eligible pay per pay period. Dividends on Duke Energy shares held by the savings plans are charged to retained earnings when declared and shares held in the plans are considered outstanding in the calculation of basic and diluted EPS.

For new and rehired employees who are not eligible to participate in Duke Energy's defined benefit plans, an additional employer contribution of 4% of eligible pay per pay period, which is subject to a three-year vesting schedule, is provided to the employee's savings plan account. Certain Piedmont employees whose participation in a prior Piedmont defined benefit plan (that was frozen as of December 31, 2017) are eligible for employer transition credit contributions of 3% to 5% of eligible pay per period, for each pay period during the three-year period ending December 31, 2020.

The following table includes pretax employer matching contributions made by Duke Energy and expensed by the Subsidiary Registrants.

(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Years ended December 31,								
2019	**$ 214**	**$ 66**	**$ 58**	**$ 38**	**$ 20**	**$ 5**	**$ 11**	**$ 13**
2018	213	68	58	40	19	4	10	12
2017	179	61	53	37	16	3	9	7

24. INCOME TAXES

Tax Act

On December 22, 2017, President Trump signed the Tax Act into law. Among other provisions, the Tax Act lowered the corporate federal income tax rate from 35% to 21%, limits interest deductions outside of regulated utility operations, requires the normalization of excess deferred taxes associated with property under the average rate assumption method as a prerequisite to qualifying for accelerated depreciation and repealed the federal manufacturing deduction. The Tax Act also repealed the corporate AMT and stipulates a refund of 50% of remaining AMT credit carryforwards (to the extent the credits exceed regular tax for the year) for tax years 2018, 2019, and 2020, with all remaining AMT credits to be refunded in tax year 2021.

On December 22, 2017, the SEC staff issued Staff Accounting Bulletin (SAB) 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provides guidance on accounting for the Tax Act's impact. SAB 118 provides a measurement period, which in no case should extend beyond one year from the Tax Act enactment date, during which a company acting in good faith may complete the accounting for the impacts of the Tax Act under ASC Topic 740. In accordance with SAB 118, a company must reflect the income tax effects of the Tax Act in the reporting period in which the accounting under ASC Topic 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete, a company can determine a reasonable estimate for those effects and record a provisional estimate in the financial statements in the first reporting period in which a reasonable estimate can be determined.

As of December 31, 2018, the accounting for the effects of the Tax Act was complete. During the year ended December 31, 2018, Duke Energy recorded the following measurement period adjustments in accordance with SAB 118:

- Additional tax expense of $23 million related to the completion of the analysis of Duke Energy's existing regulatory liability related to deferred taxes;
- A $10 million tax benefit for the remeasurement of deferred tax assets and deferred tax liabilities primarily related to the guidance on bonus depreciation issued by the IRS in August 2018, affecting the computation of the Company's 2017 Federal income tax liability;
- Additional tax expense of $7 million related to the portion of the deferred tax asset as of December 31, 2017, that represents nondeductible long-term incentives under the Tax Act's limitation on the deductibility of executive compensation; and
- During the fourth quarter of 2018, the Company released the $76 million valuation allowance that it recorded in the first quarter of 2018 as a result of additional guidance published by the IRS that stated refundable AMT credits would not be subject to sequestration.
- The majority of Duke Energy's operations are regulated and it is expected that the Subsidiary Registrants will ultimately pass on the savings associated with the amount representing the remeasurement of deferred tax balances related to regulated operations to customers. For Duke Energy's regulated operations, where the reduction is expected to be returned to customers in future rates, the remeasurement has been deferred as a regulatory liability. During 2018, Duke Energy recorded an additional regulatory liability of $83 million, representing the revaluation of those deferred tax balances. The Subsidiary Registrants continue to respond to requests from regulators in various jurisdictions to determine the timing and magnitude of savings they will pass on to customers.

In addition, during 2018, Duke Energy reclassified $573 million of AMT credit carryforwards from noncurrent deferred tax liabilities to a current federal income tax receivable. In 2019, Duke Energy received a refund of $573 million related to AMT credit carryforwards based on the filing of Duke Energy's 2018 income tax return in 2019 and reclassified $286 million of AMT credits from noncurrent deferred tax liabilities to a current federal income tax receivable.

Income Tax Expense

Components of Income Tax Expense

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Current income taxes								
Federal	$ (299)	$ 164	$ (173)	$ (36)	$ (43)	$ (41)	$ (23)	$ (92)
State	10	13	(7)	(3)	18	(1)	1	(1)
Foreign	2	—	—	—	—	—	—	—
Total current income taxes	(287)	177	(180)	(39)	(25)	(42)	(22)	(93)
Deferred income taxes								
Federal	855	175	422	220	153	77	128	133
State	(38)	(37)	17	(18)	27	5	28	3
Total deferred income taxes[a]	817	138	439	202	180	82	156	136
ITC amortization	(11)	(4)	(6)	(6)	—	—	—	—
Income tax expense from continuing operations	519	311	253	157	155	40	134	43
Tax benefit from discontinued operations	(2)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 517	$ 311	$ 253	$ 157	$ 155	$ 40	$ 134	$ 43

(a) Total deferred income taxes includes the generation of tax credit carryforwards of $8 million at Duke Energy Carolinas. In addition, total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $243 million at Progress Energy, $35 million at Duke Energy Progress, $152 million at Duke Energy Florida, $25 million at Duke Energy Ohio, $60 million at Duke Energy Indiana, $90 million at Piedmont and $775 million at Duke Energy.

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current income taxes								
Federal	$ (647)	$ (8)	$ (135)	$ (71)	$ (49)	$ 20	$ 29	$ 67
State	(11)	6	(5)	(5)	(10)	(1)	3	1
Foreign	3	—	—	—	—	—	—	—
Total current income taxes	(655)	(2)	(140)	(76)	(59)	19	32	68
Deferred income taxes								
Federal	1,064	299	341	256	115	21	74	(36)
State	49	11	20	(17)	45	3	22	5
Total deferred income taxes[a][b]	1,113	310	361	239	160	24	96	(31)
ITC amortization	(10)	(5)	(3)	(3)	—	—	—	—
Income tax expense from continuing operations	448	303	218	160	101	43	128	37
Tax benefit from discontinued operations	(26)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 422	$ 303	$ 218	$ 160	$ 101	$ 43	$ 128	$ 37

(a) Includes benefits of NOL carryforwards and tax credit carryforwards of $22 million at Duke Energy Carolinas, $293 million at Progress Energy, $59 million at Duke Energy Progress, $219 million at Duke Energy Florida, $17 million at Duke Energy Ohio, $21 million at Duke Energy Indiana and $39 million at Piedmont. In addition, total deferred income taxes includes utilization of NOL carryforwards and tax credit carryforwards of $18 million at Duke Energy.

(b) For the year ended December 31, 2018, the Company has revised the December 31, 2017, estimates of the income tax effects of the Tax Act, in accordance with SAB 118. See the Statutory Rate Reconciliation section below for additional information on the Tax Act's impact on income tax expense.

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Current income taxes								
Federal	$ (247)	$ 221	$ (436)	$ (95)	$ (188)	$ (37)	$ 128	$ (90)
State	4	20	(5)	2	(11)	2	21	(3)
Foreign	3	—	—	—	—	—	—	—
Total current income taxes	(240)	241	(441)	(93)	(199)	(35)	149	(93)
Deferred income taxes								
Federal	1,344	381	664	378	194	99	138	147
State	102	35	44	10	51	(4)	14	8
Total deferred income taxes[a][b]	1,446	416	708	388	245	95	152	155
ITC amortization	(10)	(5)	(3)	(3)	—	(1)	—	—
Income tax expense from continuing operations	1,196	652	264	292	46	59	301	62
Tax benefit from discontinued operations	(6)	—	—	—	—	—	—	—
Total income tax expense included in Consolidated Statements of Operations	$ 1,190	$ 652	$ 264	$ 292	$ 46	$ 59	$ 301	$ 62

(a) Includes utilization of NOL carryforwards and tax credit carryforwards of $428 million at Duke Energy, $74 million at Progress Energy, $36 million at Duke Energy Florida, $17 million at Duke Energy Ohio, $42 million at Duke Energy Indiana and $79 million at Piedmont. In addition, total deferred income taxes includes benefits of NOL carryforwards and tax credit carryforwards of $10 million at Duke Energy Carolinas and $1 million at Duke Energy Progress.

(b) As a result of the Tax Act, Duke Energy's deferred tax assets and liabilities were revalued as of December 31, 2017. See the Statutory Rate Reconciliation section below for additional information on the Tax Act's impact on income tax expense.

Duke Energy Income from Continuing Operations before Income Taxes

	Years Ended December 31,		
(in millions)	2019	2018	2017
Domestic[a]	**$ 4,053**	$ 3,018	$ 4,207
Foreign	**44**	55	59
Income from continuing operations before income taxes	**$ 4,097**	$ 3,073	$ 4,266

(a) Includes a $16 million expense in 2017 related to the Tax Act impact on equity earnings included within Equity in earnings of unconsolidated affiliates on the Consolidated Statement of Operations.

Statutory Rate Reconciliation

The following tables present a reconciliation of income tax expense at the U.S. federal statutory tax rate to the actual tax expense from continuing operations.

	Year Ended December 31, 2019							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Income tax expense, computed at the statutory rate of 21%	$ 860	$ 360	$ 332	$ 202	$ 178	$ 59	$ 120	$ 51
State income tax, net of federal income tax effect	(22)	(19)	8	(17)	35	3	22	2
Amortization of excess deferred income tax	(121)	(29)	(64)	(10)	(54)	(12)	(6)	(10)
AFUDC equity income	(52)	(9)	(14)	(13)	(1)	(3)	(3)	—
AFUDC equity depreciation	34	19	10	5	5	1	4	—
Renewable energy PTCs	(120)	—	—	—	—	—	—	—
Other tax credits	(23)	(11)	(9)	(7)	(2)	(1)	(1)	(1)
Tax true up	(64)	(9)	(8)	(3)	(5)	(7)	(1)	—
Other items, net	27	9	(2)	—	(1)	—	(1)	1
Income tax expense from continuing operations	$ 519	$ 311	$ 253	$ 157	$ 155	$ 40	$ 134	$ 43
Effective tax rate	12.7%	18.1%	16.0%	16.3%	18.3%	14.3%	23.5%	17.6%

	Year Ended December 31, 2018							
(in millions)	**Duke Energy**	**Duke Energy Carolinas**	**Progress Energy**	**Duke Energy Progress**	**Duke Energy Florida**	**Duke Energy Ohio**	**Duke Energy Indiana**	**Piedmont**
Income tax expense, computed at the statutory rate of 21%	$ 645	$ 288	$ 263	$ 174	$ 137	$ 46	$ 109	$ 35
State income tax, net of federal income tax effect	30	14	13	(17)	28	2	20	4
Amortization of excess deferred income tax	(61)	—	(55)	(1)	(54)	(3)	(2)	—
AFUDC equity income	(42)	(15)	(22)	(12)	(10)	(2)	(2)	—
AFUDC equity depreciation	31	18	9	5	4	1	4	—
Renewable energy PTCs	(129)	—	—	—	—	—	—	—
Other tax credits	(28)	(7)	(13)	(5)	(8)	(1)	(1)	(3)
Tax Act[a]	20	1	25	19	—	2	—	—
Other items, net	(18)	4	(2)	(3)	4	(2)	—	1
Income tax expense from continuing operations	$ 448	$ 303	$ 218	$ 160	$ 101	$ 43	$ 128	$ 37
Effective tax rate	14.6%	22.1%	17.4%	19.3%	15.4%	19.6%	24.6%	22.3%

(a) For the year ended December 31, 2018, the Company revised the December 31, 2017 estimates of the income tax effects of the Tax Act, in accordance with SAB 118. Amounts primarily include but are not limited to items that are excluded for ratemaking purposes related certain wholesale fixed rate contracts, remeasurement of nonregulated net deferred tax liabilities, Federal NOLs, and valuation allowance on foreign tax credits.

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Income tax expense, computed at the statutory rate of 35%	$ 1,493	$ 653	$ 536	$ 353	$ 265	$ 88	$ 229	$ 70
State income tax, net of federal income tax effect	69	36	25	8	26	(1)	23	3
AFUDC equity income	(81)	(37)	(32)	(17)	(16)	(4)	(8)	—
Renewable energy PTCs	(132)	—	—	—	—	—	—	—
Tax Act[a]	(112)	15	(246)	(40)	(226)	(23)	55	(12)
Tax true up	(52)	(24)	(19)	(13)	(7)	(5)	(6)	—
Other items, net	11	9	—	1	4	4	8	1
Income tax expense from continuing operations	$ 1,196	$ 652	$ 264	$ 292	$ 46	$ 59	$ 301	$ 62
Effective tax rate	28.0%	34.9%	17.2%	29.0%	6.1%	23.4%	46.0%	30.8%

(a) Amounts primarily include but are not limited to items that are excluded for ratemaking purposes related to abandoned or impaired assets, certain wholesale fixed rate contracts, remeasurement of nonregulated net deferred tax liabilities, Federal NOLs, and valuation allowance on foreign tax credits.

Valuation allowances have been established for certain state NOL carryforwards and state income tax credits that reduce deferred tax assets to an amount that will be realized on a more-likely-than-not basis. The net change in the total valuation allowance is included in State income tax, net of federal income tax effect, in the above tables.

Valuation allowances have been established for foreign tax credits that reduce deferred tax assets to an amount that will be realized on a more-likely-than-not basis. The net change in the total valuation allowance is included in Tax Act in the above tables.

DEFERRED TAXES

Net Deferred Income Tax Liability Components

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Deferred credits and other liabilities	$ 125	$ 24	$ 25	$ 49	$ —	$ 14	$ 5	$ 22
Lease obligations	462	72	193	92	102	5	17	6
Pension, post-retirement and other employee benefits	303	(5)	88	38	44	17	27	(3)
Progress Energy merger purchase accounting adjustments(a)	389	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	3,925	262	486	176	253	16	176	19
Regulatory liabilities and deferred credits	—	—	—	—	—	36	52	42
Investments and other assets	—	—	—	—	—	10	—	2
Other	97	5	8	3	2	8	1	6
Valuation allowance	(587)	—	—	—	—	—	—	—
Total deferred income tax assets	4,714	358	800	358	401	106	278	94
Investments and other assets	(1,664)	(981)	(577)	(390)	(190)	—	(12)	—
Accelerated depreciation rates	(10,813)	(3,254)	(3,798)	(1,918)	(1,913)	(1,028)	(1,416)	(802)
Regulatory assets and deferred debits, net	(1,115)	(44)	(887)	(438)	(477)	—	—	—
Total deferred income tax liabilities	(13,592)	(4,279)	(5,262)	(2,746)	(2,580)	(1,028)	(1,428)	(802)
Net deferred income tax liabilities	$ (8,878)	$ (3,921)	$ (4,462)	$ (2,388)	$ (2,179)	$ (922)	$ (1,150)	$ (708)

(a) Primarily related to finance lease obligations and debt fair value adjustments.

The following table presents the expiration of tax credits and NOL carryforwards.

	December 31, 2019	
(in millions)	Amount	Expiration Year
General Business Credits	$ 1,821	2024 — 2039
AMT credits	286	Refundable by 2021
Federal NOL carryforwards(a) (f)	169	2024 — Indefinite
Capital loss carryforward(e)	87	2024
State carryforwards and credits(b) (f)	303	2020 — Indefinite
Foreign NOL carryforwards(c)	12	2027 — 2037
Foreign Tax Credits(d)	1,237	2024 — 2027
Charitable contribution carryforwards	10	2020 — 2024
Total tax credits and NOL carryforwards	$ 3,925	

A valuation allowance of $4 million has been recorded on the Federal NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(b) A valuation allowance of $97 million has been recorded on the state NOL and credit carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(c) A valuation allowance of $12 million has been recorded on the foreign NOL carryforwards, as presented in the Net Deferred Income Tax Liability Components table.

(d) A valuation allowance of $387 million has been recorded on the foreign tax credits, as presented in the Net Deferred Income Tax Liability Components table.

(e) A valuation allowance of $87 million has been recorded on the Federal capital loss carryforward, as presented in the Net Deferred Income Tax Liability Components table.

(f) Indefinite carryforward for Federal NOLs, and NOLs for states that have adopted the Tax Act's NOL provisions, generated in tax years beginning after December 31, 2017.

	December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Deferred credits and other liabilities	$ 164	$ 64	$ 35	$ 53	$ —	$ 17	$ 6	$ 17
Finance lease obligations	60	26	—	—	—	—	2	—
Pension, post-retirement and other employee benefits	347	24	110	47	58	16	24	(1)
Progress Energy merger purchase accounting adjustments[a]	483	—	—	—	—	—	—	—
Tax credits and NOL carryforwards	4,580	257	693	215	363	42	237	110
Regulatory liabilities and deferred credits	—	—	—	—	—	56	—	48
Investments and other assets	—	—	—	—	—	18	—	16
Other	25	6	5	5	—	1	(1)	—
Valuation allowance	(484)	—	—	—	—	—	—	—
Total deferred income tax assets	5,175	377	843	320	421	150	268	190
Investments and other assets	(1,317)	(795)	(430)	(272)	(163)	—	(5)	—
Accelerated depreciation rates	(10,124)	(3,207)	(3,369)	(1,735)	(1,670)	(967)	(1,081)	(733)
Regulatory assets and deferred debits, net	(1,540)	(64)	(985)	(432)	(574)	—	(191)	—
Other	—	—	—	—	—	—	—	(8)
Total deferred income tax liabilities	(12,981)	(4,066)	(4,784)	(2,439)	(2,407)	(967)	(1,277)	(741)
Net deferred income tax liabilities	$ (7,806)	$ (3,689)	$ (3,941)	$ (2,119)	$ (1,986)	$ (817)	$ (1,009)	$ (551)

(a) Primarily related to finance lease obligations and debt fair value adjustments.

UNRECOGNIZED TAX BENEFITS

The following tables present changes to unrecognized tax benefits.

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 24	$ 6	$ 9	$ 6	$ 3	$ 1	$ 1	$ 4
Unrecognized tax benefit increases	105	2	1	1	—	—	—	—
Gross decreases – tax positions in prior periods	(3)	—	(1)	(1)	—	—	—	—
Total changes	102	2	—	—	—	—	—	—
Unrecognized tax benefits – December 31	$ 126	$ 8	$ 9	$ 6	$ 3	$ 1	$ 1	$ 4

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 25	$ 5	$ 5	$ 5	$ 5	$ 1	$ 1	$ 3
Unrecognized tax benefits increases (decreases)								
Gross decreases – tax positions in prior periods	(2)	(1)	—	—	(4)	—	—	—
Gross increases – tax positions in prior periods	7	2	4	1	2	—	—	1
Decreases due to settlements	(6)	—	—	—	—	—	—	—
Total changes	(1)	1	4	1	(2)	—	—	1
Unrecognized tax benefits – December 31	$ 24	$ 6	$ 9	$ 6	$ 3	$ 1	$ 1	$ 4

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Unrecognized tax benefits – January 1	$ 17	$ 1	$ 2	$ 2	$ 4	$ 4	$ —	$ —
Unrecognized tax benefits increases (decreases)								
Gross increases – tax positions in prior periods	12	4	3	3	1	1	1	3
Gross decreases – tax positions in prior periods	(4)	—	—	—	—	(4)	—	—
Total changes	8	4	3	3	1	(3)	1	3
Unrecognized tax benefits – December 31	$ 25	$ 5	$ 5	$ 5	$ 5	$ 1	$ 1	$ 3

The following table includes additional information regarding the Duke Energy Registrants' unrecognized tax benefits at December 31, 2019. It is reasonably possible that Duke Energy will reflect a $3 million decrease in unrecognized tax benefits within the next 12 months.

	December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Amount that if recognized, would affect the effective tax rate or regulatory liability[a]	$ 122	$ 8	$ 9	$ 6	$ 3	$ 1	$ 1	$ 4

(a) The Duke Energy Registrants are unable to estimate the specific amounts that would affect the effective tax rate versus the regulatory liability.

OTHER TAX MATTERS

The following tables include interest recognized in the Consolidated Statements of Operations and the Consolidated Balance Sheets.

	Year Ended December 31, 2019			
(in millions)	Duke Energy	Progress Energy	Duke Energy Progress	Piedmont
Net interest income recognized related to income taxes	$ 16	$ 1	$ 1	$ —
Interest receivable related to income taxes	1	—	—	—
Interest payable related to income taxes	1	—	—	1

	Year Ended December 31, 2018		
(in millions)	Duke Energy	Progress Energy	Duke Energy Progress
Net interest income recognized related to income taxes	$ 2	$ —	$ —
Interest payable related to income taxes	3	1	1

	Year Ended December 31, 2017				
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida
Net interest income recognized related to income taxes	$ —	$ —	$ 1	$ —	$ 1
Net interest expense recognized related to income taxes	—	2	—	—	—
Interest payable related to income taxes	5	25	1	1	—

Duke Energy and its subsidiaries are no longer subject to U.S. federal examination for years before 2016. With few exceptions, Duke Energy and its subsidiaries are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2016.

25. OTHER INCOME AND EXPENSES, NET

The components of Other income and expenses, net on the Consolidated Statements of Operations are as follows.

	Year Ended December 31, 2019							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Interest income	$ 31	$ 1	$ 11	$ —	$ 11	$ 10	$ 10	$ 1
AFUDC equity	139	42	66	60	6	13	18	—
Post in-service equity returns	29	20	7	7	—	1	—	—
Nonoperating income, other	231	88	57	33	31	—	13	19
Other income and expense, net	$ 430	$ 151	$ 141	$ 100	$ 48	$ 24	$ 41	$ 20

	Year Ended December 31, 2018							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Interest income	$ 20	$ 1	$ 18	$ 1	$ 18	$ 7	$ 9	$ 1
AFUDC equity	221	73	104	57	47	11	32	—
Post in-service equity returns	15	9	5	5	—	1	—	—
Nonoperating income, other	143	70	38	24	21	4	4	13
Other income and expense, net	$ 399	$ 153	$ 165	$ 87	$ 86	$ 23	$ 45	$ 14

	Year Ended December 31, 2017							
(in millions)	Duke Energy	Duke Energy Carolinas	Progress Energy	Duke Energy Progress	Duke Energy Florida	Duke Energy Ohio	Duke Energy Indiana	Piedmont
Interest income	$ 13	$ 2	$ 6	$ 2	$ 5	$ 6	$ 8	$ —
AFUDC equity	237	106	92	47	45	11	28	—
Post in-service equity returns	40	28	12	12	—	—	—	—
Nonoperating income, other	218	63	99	54	46	6	11	(11)
Other income and expense, net	$ 508	$ 199	$ 209	$ 115	$ 96	$ 23	$ 47	$ (11)

26. SUBSEQUENT EVENTS

For information on subsequent events related to the adoption of the new credit losses accounting standard, regulatory matters and debt and credit facilities, see Notes 1, 4 and 7, respectively.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.
2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.
3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.
4. Report data on a year-to-date basis.

Line No.	Item (a)	Unrealized Gains and Losses on Available-for-Sale Securities (b)	Minimum Pension Liability adjustment (net amount) (c)	Foreign Currency Hedges (d)	Other Adjustments (e)
1	Balance of Account 219 at Beginning of Preceding Year	(1)			
2	Preceding Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
3	Preceding Quarter/Year to Date Changes in Fair Value				
4	Total (lines 2 and 3)				
5	Balance of Account 219 at End of Preceding Quarter/Year	(1)			
6	Balance of Account 219 at Beginning of Current Year	(1)			
7	Current Qtr/Yr to Date Reclassifications from Acct 219 to Net Income				
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				
10	Balance of Account 219 at End of Current Quarter/Year	(1)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STATEMENTS OF ACCUMULATED COMPREHENSIVE INCOME, COMPREHENSIVE INCOME, AND HEDGING ACTIVITIES

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(7,080,443)		(7,080,444)		
2	912,553		912,553		
3					
4	912,553		912,553	1,070,378,654	1,071,291,207
5	(6,167,890)		(6,167,891)		
6	(6,167,890)		(6,167,891)		
7	(1,118,952)		(1,118,952)		
8					
9	(1,118,952)		(1,118,952)	1,402,188,500	1,401,069,548
10	(7,286,842)		(7,286,843)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Report in Column (c) the amount for electric function, in column (d) the amount for gas function, in column (e), (f), and (g) report other (specify) and in column (h) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	38,649,231,134	38,649,231,134
4	Property Under Capital Leases	334,112,417	334,112,417
5	Plant Purchased or Sold		
6	Completed Construction not Classified	6,604,179,898	6,604,179,898
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	45,587,523,449	45,587,523,449
9	Leased to Others		
10	Held for Future Use	61,165,859	61,165,859
11	Construction Work in Progress	1,377,950,765	1,377,950,765
12	Acquisition Adjustments	284,106	284,106
13	Total Utility Plant (8 thru 12)	47,026,924,179	47,026,924,179
14	Accum Prov for Depr, Amort, & Depl	16,817,702,401	16,817,702,401
15	Net Utility Plant (13 less 14)	30,209,221,778	30,209,221,778
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	16,134,588,339	16,134,588,339
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	682,834,408	682,834,408
22	Total In Service (18 thru 21)	16,817,422,747	16,817,422,747
23	Leased to Others		
24	Depreciation		
25	Amortization and Depletion		
26	Total Leased to Others (24 & 25)		
27	Held for Future Use		
28	Depreciation		
29	Amortization		
30	Total Held for Future Use (28 & 29)		
31	Abandonment of Leases (Natural Gas)		
32	Amort of Plant Acquisition Adj	279,654	279,654
33	Total Accum Prov (equals 14) (22,26,30,31,32)	16,817,702,401	16,817,702,401

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUMMARY OF UTILITY PLANT AND ACCUMULATED PROVISIONS
FOR DEPRECIATION. AMORTIZATION AND DEPLETION

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
					4
					5
					6
					7
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					9
					10
					11
					12
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					14
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					31
					32
					33

FOOTNOTE DATA

Schedule Page: 200 Line No.: 4 Column: c

Property under Capital Leases includes both Capital and Operating Leases. Capital Leases of $210,738,443 and Net Operating Leases of $123,373,975.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

1. Report below the costs incurred for nuclear fuel materials in process of fabrication, on hand, in reactor, and in cooling; owned by the respondent.
2. If the nuclear fuel stock is obtained under leasing arrangements, attach a statement showing the amount of nuclear fuel leased, the quantity used and quantity on hand, and the costs incurred under such leasing arrangements.

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
2	Fabrication	6,731,527	31,605,867
3	Nuclear Materials	222,925,516	222,604,673
4	Allowance for Funds Used during Construction	46,810,624	13,244,423
5	(Other Overhead Construction Costs, provide details in footnote)		
6	SUBTOTAL (Total 2 thru 5)	276,467,667	
7	Nuclear Fuel Materials and Assemblies		
8	In Stock (120.2)	1	190,080,221
9	In Reactor (120.3)	1,152,233,077	190,080,221
10	SUBTOTAL (Total 8 & 9)	1,152,233,078	
11	Spent Nuclear Fuel (120.4)	475,269,001	233,390,362
12	Nuclear Fuel Under Capital Leases (120.6)		
13	(Less) Accum Prov for Amortization of Nuclear Fuel Assem (120.5)	1,089,674,019	
14	TOTAL Nuclear Fuel Stock (Total 6, 10, 11, 12, less 13)	814,295,727	
15	Estimated net Salvage Value of Nuclear Materials in line 9		
16	Estimated net Salvage Value of Nuclear Materials in line 11		
17	Est Net Salvage Value of Nuclear Materials in Chemical Processing		
18	Nuclear Materials held for Sale (157)		
19	Uranium		
20	Plutonium		
21	Other (provide details in footnote):		
22	TOTAL Nuclear Materials held for Sale (Total 19, 20, and 21)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

Changes during Year		Balance	Line
Amortization (d)	Other Reductions (Explain in a footnote) (e)	End of Year (f)	No.
			1
	28,143,891	10,193,503	2
	152,349,934	293,180,255	3
	9,586,396	50,468,651	4
			5
		353,842,409	6
			7
	190,080,221	1	8
	233,390,362	1,108,922,936	9
		1,108,922,937	10
	274,240,145	434,419,218	11
			12
-270,484,487	274,240,145	1,085,918,361	13
		811,266,203	14
			15
			16
			17
			18
			19
			20
			21
			22

FOOTNOTE DATA

Schedule Page: 202 Line No.: 2 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 3 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 4 Column: e

Transfer of nuclear materials and assemblies to stock.

Schedule Page: 202 Line No.: 8 Column: e

Transfer to reactor.

Schedule Page: 202 Line No.: 9 Column: e

Reflects nuclear fuel assemblies transferred to the spent fuel pool.

Schedule Page: 202 Line No.: 11 Column: e

Reflects nuclear fuel assemblies retired from the reactor.

Schedule Page: 202 Line No.: 13 Column: e

Reflects nuclear fuel assemblies retired from the reactor.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106)

1. Report below the original cost of electric plant in service according to the prescribed accounts.
2. In addition to Account 101, Electric Plant in Service (Classified), this page and the next include Account 102, Electric Plant Purchased or Sold; Account 103, Experimental Electric Plant Unclassified; and Account 106, Completed Construction Not Classified-Electric.
3. Include in column (c) or (d), as appropriate, corrections of additions and retirements for the current or preceding year.
4. For revisions to the amount of initial asset retirement costs capitalized, included by primary plant account, increases in column (c) additions and reductions in column (e) adjustments.
5. Enclose in parentheses credit adjustments of plant accounts to indicate the negative effect of such accounts.
6. Classify Account 106 according to prescribed accounts, on an estimated basis if necessary, and include the entries in column (c). Also to be included in column (c) are entries for reversals of tentative distributions of prior year reported in column (b). Likewise, if the respondent has a significant amount of plant retirements which have not been classified to primary accounts at the end of the year, include in column (d) a tentative distribution of such retirements, on an estimated basis, with appropriate contra entry to the account for accumulated depreciation provision. Include also in column (d)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
1	1. INTANGIBLE PLANT		
2	(301) Organization		
3	(302) Franchises and Consents	10,634,028	180,901,850
4	(303) Miscellaneous Intangible Plant	976,116,842	-123,723,388
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	986,750,870	57,178,462
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	28,932,847	3,107,164
9	(311) Structures and Improvements	1,084,756,930	287,764,246
10	(312) Boiler Plant Equipment	5,494,975,319	193,298,039
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	955,961,099	7,590,240
13	(315) Accessory Electric Equipment	395,870,694	6,612,661
14	(316) Misc. Power Plant Equipment	364,859,567	7,219,300
15	(317) Asset Retirement Costs for Steam Production	886,954,101	1,783,514,455
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	9,212,310,557	2,289,106,105
17	B. Nuclear Production Plant		
18	(320) Land and Land Rights	3,041,443	
19	(321) Structures and Improvements	1,895,754,636	51,480,679
20	(322) Reactor Plant Equipment	3,844,463,636	72,019,395
21	(323) Turbogenerator Units	977,902,638	59,803,396
22	(324) Accessory Electric Equipment	1,229,197,356	61,314,049
23	(325) Misc. Power Plant Equipment	571,176,098	23,810,595
24	(326) Asset Retirement Costs for Nuclear Production	-333,080,605	81,564,835
25	TOTAL Nuclear Production Plant (Enter Total of lines 18 thru 24)	8,188,455,202	349,992,949
26	C. Hydraulic Production Plant		
27	(330) Land and Land Rights	52,346,850	734,448
28	(331) Structures and Improvements	408,599,840	27,491,485
29	(332) Reservoirs, Dams, and Waterways	849,982,333	124,780,205
30	(333) Water Wheels, Turbines, and Generators	657,895,468	83,893,072
31	(334) Accessory Electric Equipment	143,076,932	5,464,388
32	(335) Misc. Power PLant Equipment	52,838,344	2,676,184
33	(336) Roads, Railroads, and Bridges	21,796,265	
34	(337) Asset Retirement Costs for Hydraulic Production		14,403,254
35	TOTAL Hydraulic Production Plant (Enter Total of lines 27 thru 34)	2,186,536,032	259,443,036
36	D. Other Production Plant		
37	(340) Land and Land Rights	9,363,772	-137,490
38	(341) Structures and Improvements	368,014,132	17,711,908
39	(342) Fuel Holders, Products, and Accessories	182,901,175	7,182,352
40	(343) Prime Movers	1,334,931,655	133,495,783
41	(344) Generators	1,000,725,921	116,542
42	(345) Accessory Electric Equipment	213,706,288	7,700,913
43	(346) Misc. Power Plant Equipment	38,133,276	7,589,711
44	(347) Asset Retirement Costs for Other Production	14,776,081	
45	TOTAL Other Prod. Plant (Enter Total of lines 37 thru 44)	3,162,552,300	173,659,719
46	TOTAL Prod. Plant (Enter Total of lines 16, 25, 35, and 45)	22,749,854,091	3,072,201,809

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Line No.	Account (a)	Balance Beginning of Year (b)	Additions (c)
47	3. TRANSMISSION PLANT		
48	(350) Land and Land Rights	196,373,359	672,651
49	(352) Structures and Improvements	103,796,703	66,071,697
50	(353) Station Equipment	1,839,755,500	231,126,285
51	(354) Towers and Fixtures	587,645,123	38,872,142
52	(355) Poles and Fixtures	558,684,531	38,670,747
53	(356) Overhead Conductors and Devices	760,513,689	73,772,782
54	(357) Underground Conduit	124,174	3,163
55	(358) Underground Conductors and Devices	5,812,002	3,870,499
56	(359) Roads and Trails	42,238	
57	(359.1) Asset Retirement Costs for Transmission Plant		
58	TOTAL Transmission Plant (Enter Total of lines 48 thru 57)	4,052,747,319	453,059,966
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	63,781,603	1,885,041
61	(361) Structures and Improvements	112,827,983	43,458,231
62	(362) Station Equipment	1,376,647,877	127,503,253
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	1,633,135,516	90,240,385
65	(365) Overhead Conductors and Devices	2,263,640,320	160,998,420
66	(366) Underground Conduit	203,949,850	14,453,326
67	(367) Underground Conductors and Devices	2,040,861,817	167,155,010
68	(368) Line Transformers	1,518,704,424	89,588,324
69	(369) Services	1,107,500,564	95,553,590
70	(370) Meters	607,348,113	40,982,542
71	(371) Installations on Customer Premises	914,011,910	94,141,235
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	243,393,600	21,059,148
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	12,085,803,577	947,018,505
76	5. REGIONAL TRANSMISSION AND MARKET OPERATION PLANT		
77	(380) Land and Land Rights		
78	(381) Structures and Improvements		
79	(382) Computer Hardware		
80	(383) Computer Software		
81	(384) Communication Equipment		
82	(385) Miscellaneous Regional Transmission and Market Operation Plant		
83	(386) Asset Retirement Costs for Regional Transmission and Market Oper		
84	TOTAL Transmission and Market Operation Plant (Total lines 77 thru 83)		
85	6. GENERAL PLANT		
86	(389) Land and Land Rights	62,917,137	
87	(390) Structures and Improvements	675,049,909	50,052,030
88	(391) Office Furniture and Equipment	162,588,557	32,924,280
89	(392) Transportation Equipment	12,636,777	1,626,513
90	(393) Stores Equipment	14,298,929	420,241
91	(394) Tools, Shop and Garage Equipment	104,793,596	6,463,967
92	(395) Laboratory Equipment	5,877,459	1,280,319
93	(396) Power Operated Equipment	11,327,986	1,993,062
94	(397) Communication Equipment	153,219,179	54,255,147
95	(398) Miscellaneous Equipment	10,275,692	1,962,932
96	SUBTOTAL (Enter Total of lines 86 thru 95)	1,212,985,221	150,978,491
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant	-931,335	
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	1,212,053,886	150,978,491
100	TOTAL (Accounts 101 and 106)	41,087,209,743	4,680,437,233
101	(102) Electric Plant Purchased (See Instr. 8)		
102	(Less) (102) Electric Plant Sold (See Instr. 8)		
103	(103) Experimental Plant Unclassified		
104	TOTAL Electric Plant in Service (Enter Total of lines 100 thru 103)	41,087,209,743	4,680,437,233

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

distributions of these tentative classifications in columns (c) and (d), including the reversals of the prior years tentative account distributions of these amounts. Careful observance of the above instructions and the texts of Accounts 101 and 106 will avoid serious omissions of the reported amount of respondent's plant actually in service at end of year.

7. Show in column (f) reclassifications or transfers within utility plant accounts. Include also in column (f) the additions or reductions of primary account classifications arising from distribution of amounts initially recorded in Account 102, include in column (e) the amounts with respect to accumulated provision for depreciation, acquisition adjustments, etc., and show in column (f) only the offset to the debits or credits distributed in column (f) to primary account classifications.

8. For Account 399, state the nature and use of plant included in this account and if substantial in amount submit a supplementary statement showing subaccount classification of such plant conforming to the requirement of these pages.

9. For each amount comprising the reported balance and changes in Account 102, state the property purchased or sold, name of vendor or purchase, and date of transaction. If proposed journal entries have been filed with the Commission as required by the Uniform System of Accounts, give also date

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
51,514			191,484,364		3
1,493,358			850,900,096		4
1,544,872			1,042,384,460		5
					6
					7
15,641		-5,174	32,019,196		8
-24,834,982		-2,922,203	1,394,433,955		9
-20,094,268		-1,801,937	5,706,565,689		10
					11
5,637,545		-132,480	957,781,314		12
2,191,467			400,291,888		13
-282,376			372,361,243		14
-47,678,938			2,718,147,494		15
-85,045,911		-4,861,794	11,581,600,779		16
					17
			3,041,443		18
17,833,889			1,929,401,426		19
16,820,924			3,899,662,107		20
21,937,662			1,015,768,372		21
1,432,515			1,289,078,890		22
-108,334			595,095,027		23
			-251,515,770		24
57,916,656			8,480,531,495		25
					26
771,807			52,309,491		27
6,048,685			430,042,640		28
25,047,506			949,715,032		29
24,756,443			717,032,097		30
10,013,838			138,527,482		31
1,180,441		-425,944	53,908,143		32
			21,796,265		33
14,403,254					34
82,221,974		-425,944	2,363,331,150		35
					36
		5,174	9,231,456		37
-145,643		2,922,203	388,793,886		38
485,115			189,598,412		39
56,013,449		132,480	1,412,546,469		40
-16,195,628			1,017,038,091		41
80,626			221,326,575		42
476,884			45,246,103		43
	-161,076		14,615,005		44
40,714,803	-161,076	3,059,857	3,298,395,997		45
95,807,522	-161,076	-2,227,881	25,723,859,421		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC PLANT IN SERVICE (Account 101, 102, 103 and 106) (Continued)

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
324,255			196,721,755		48
2,794,328		-80,170	166,993,902		49
26,271,537		-1,123,173	2,043,487,075		50
2,178,393			624,338,872		51
2,395,933		410,548	595,369,893		52
3,138,858		-308,078	830,839,535		53
			127,337		54
303,938			9,378,563		55
			42,238		56
					57
37,407,242		-1,100,873	4,467,299,170		58
					59
1,658			65,664,986		60
537,210		80,170	155,829,174		61
11,018,880		1,197,576	1,494,329,826		62
					63
9,375,619		694	1,714,000,976		64
23,489,600		322,780	2,401,471,920		65
115,242			218,287,934		66
9,593,833			2,198,422,994		67
4,682,556			1,603,610,192		68
3,498,207			1,199,555,947		69
64,121,030			584,209,625		70
9,662,795			998,490,350		71
					72
3,653,245			260,799,503		73
					74
139,749,875		1,601,220	12,894,673,427		75
					76
					77
					78
					79
					80
					81
					82
					83
					84
					85
			62,917,137		86
11,627,676			713,474,263		87
7,590,678			187,922,159		88
344,204			13,919,086		89
131,769			14,587,401		90
1,232,570			110,024,993		91
574,698			6,583,080		92
16,278			13,304,770		93
6,025,788		-74,403	201,374,135		94
-518,683			12,757,307		95
27,024,978		-74,403	1,336,864,331		96
					97
			-931,335		98
27,024,978		-74,403	1,335,932,996		99
301,534,489	-161,076	-1,801,937	45,464,149,474		100
					101
					102
					103
301,534,489	-161,076	-1,801,937	45,464,149,474		104

FOOTNOTE DATA

Schedule Page: 204 Line No.: 104 Column: g

These balances include Capital Leases, but exclude Operating Leases.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
3					
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6					
7					
8					
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11					
12					
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14					
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40					
41					
42					
43					
44					
45					
46					
47	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

1. Report separately each property held for future use at end of the year having an original cost of $250,000 or more. Group other items of property held for future use.
2. For property having an original cost of $250,000 or more previously used in utility operations, now held for future use, give in column (a), in addition to other required information, the date that utility use of such property was discontinued, and the date the original cost was transferred to Account 105.

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	BELMEADE RETAIL - MECKLENBURG, NC	11/2012	2020	804,674
3	BRANSON MILL RD RETAIL - RANDOLPH, NC	11/2013	2022	572,418
4	CALICO RD RETAIL - CALDWELL, NC	1/2012	2020	427,771
5	DORMAN RD RETAIL - MECKLENBURG, NC	6/2012	2020	459,800
6	EDGEFIELD RETAIL - GUILFORD, NC	2/2012	2020	410,587
7	FURR ROAD RETAIL - MECKLENBURG, NC	10/2011	2022	1,227,200
8	GALENOR THREE BREAKER STATION - CALDWELL, NC	10/2017	2040	911,520
9	HERMAN RD RETAIL - CATAWBA, NC	4/2016	2025	351,579
10	HIGHWAY 24 RETAIL - ANDERSON, SC	12/2008	2022	384,198
11	KANOY RETAIL SUBSTATION - DAVIDSON, NC	7/2010	2021	575,861
12	KEOWEE PLT PICKENS INSURABLE - PICKENS, SC	10/2016	2030	284,915
13	KERWIN CIRCLE RETAIL - FORSYTH, NC	6/2009	2022	512,463
14	MATRIX RETAIL - GREENVILLE, SC	3/2016	2020	415,171
15	N ALEXANDER ST RETAIL SUB - MECKLENBURG, NC	3/2012	2020	959,967
16	REVOLUTION MILL RETAIL SUBSTATION - GUILFORD, NC	10/2011	2023	400,257
17	SOCK HILL RETAIL - SPARTANBURG, SC	1/2017	2020	628,785
18	ROEBUCK RETAIL LOT - SPARTANBURG, SC	2/2012	2024	364,453
19	SHOFNER RETAIL SUBSTATION - GUILFORD, NC	12/2009	2022	512,693
20	SKYLAND RETAIL - FORSYTH, NC	1/1990	2025	303,819
21	Other Property:			
22	LAKE NORMAN 525KV RIGHT OF WAY - MECKLENBURG, NC	1/1980	2024	937,983
23	LITTLE MOUNTAIN ROAD RETAIL - GASTONIA, NC	12/2008	2022	282,811
24	LONG ISLAND ROAD RETAIL - CATAWBA, NC	5/2009	2022	369,681
25	LEE NUCLEAR PLANT COMMON - CHEROKEE, SC	6/2018	2025	40,939,833
26	BALLANTYNE STATION LOT - MECKLENBURG, NC	4/2018	2020	679,432
27	RICHBURG RETAIL STATION - CHESTER, SC	1/2017	2023	1,467,035
28	PATTERSON SPRINGS RETAIL - CLEVELAND, NC	1/2017	2020	809,438
29	STOCKESDALE RETAIL - GUILFORD, NC	5/2016	2022	536,572
30	LAYCOCK RETAIL - HENDERSON, NC	10/2016	2020	523,233
31	CANTERBURRY RETAIL - GREENVILLE, SC	4/2016	2020	415,864
32	LIBERTY SITE - GUILFORD, NC	1/2017	2023	385,745
33	Other Land and Land Rights <$250K Each (52 Items)			3,310,101
34				
35				
36				
37				
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41				
42				
43				
44				
45				
46				
47	Total			61,165,859

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	DISTRIBUTION PLANT	
2		
3	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NORTH CAROLINA	53,423,418
4	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NP&L NORTH CAROLINA	13,430,489
5	KENILWORTH RETAIL - SUBSTATION CAPACITY	10,531,716
6	SMARTGRID CABLE	9,948,831
7	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - SOUTH CAROLINA	9,538,758
8	SMARTGRID FEEDER CAPACITY	8,584,915
9	CRAMERTON SUBSTATION	7,472,165
10	HERMAN ROAD SUBSTATION	5,846,225
11	EASTOVER RETAIL - TRANSFORMER BANK ADDITION	5,783,140
12	LAKE LATHAM SUBSTATION	5,414,834
13	SMARTGRID TARGETED OVERHEAD/UNDERGROUND CONVERSION	4,827,136
14	SMARTGRID SELF-HEALING TEAMS	4,622,568
15	DISTRIBUTION LIGHTING INSTALLATION - NORTH CAROLINA	4,049,030
16	BUSTER BOYD RETAIL - NEW SUBSTATION WITH TWO NEW CIRCUITS	3,968,662
17	BUSINESS UNIT 20017 DISTRIBUTION SUBSTATION	3,874,510
18	DISTRIBUTION LINE RELOCATIONS/MODIFICATIONS - NORTH CAROLINA	3,612,703
19	HIGH VISTA PARENT PHASE LOOP	3,533,477
20	LONG DURATION OUTAGES	3,141,522
21	WADDELL ROAD RETAIL - TRANSFORMER BANK ADDITION	3,090,171
22	FERNCLIFF LAND ACQUISITION	3,067,266
23	HEATH RETAIL TRANSFORMER BANK	2,387,105
24	DEATH VALLEY NEW SUBSTATION	2,382,589
25	LAKE LURE - COLUMBUS - SUNNY VIEW LINES	2,127,697
26	CHARLOTTE AUTOMATION AND INTEGRATION	2,096,447
27	WADDELL ROAD RETAIL - TRANSFORMER BANKS	2,079,967
28	KNIGHTS RETAIL - NEW CIRCUIT	1,806,626
29	DACIAN AVENUE RETAIL - TRANSFORMER	1,691,713
30	DISTRIBUTION OVERHEAD/UNDERGROUND LINE IMPROVEMENTS - NP&L CHEROKEE	1,601,264
31	LAYCOCK SUBSTATION	1,492,426
32	SMARTGRID DETERIORATED CONDUCTOR	1,483,944
33	AURIGA POLYMERS SWITCH	1,475,324
34	SPEEDWAY 2411 RECONDUCTOR	1,428,950
35	FAIRFIELD MOUNTAIN RESORT	1,354,392
36	MCADENVILLE CIRCUIT	1,348,506
37	CORINTH RETAIL RECONDUCTORING	1,344,075
38	DISTRIBUTION LIGHTING INSTALLATION - NP&L	1,319,780
39	PARADISE RETAIL GENERATOR	1,314,738
40	I-85 WIDENING PROJECT - SPARTANBURG	1,311,237
41	HINSHAW RETAIL	1,161,431
42	RUFF SOLAR INTERCONNECTION	1,119,523
43	TOTAL	1,377,950,765

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	ST. CLARKS CHAPEL DEPOT	1,102,509
2	DISTRIBUTION LIGHTING	1,090,316
3	DISTRIBUTION LINE RELOCATIONS/MODIFICATIONS - SOUTH CAROLINA	1,054,764
4	PROJECTS LESS THAN $1 MILLION	53,699,794
5	TOTAL DISTRIBUTION PLANT $257,036,653	
6		
7	GENERAL PLANT	
8		
9	CHARLOTTE METRO - CONSTRUCT NEW OFFICE TOWER	40,993,504
10	REAL ESTATE SERVICES - MISCELLANEOUS CAROLINAS WEST GENERAL PLANT PROJECTS	17,295,211
11	GENERAL ACCRUAL FOR DUKE POWER	13,509,514
12	STRATEGIC COMMUNICATION	5,985,579
13	REAL ESTATE SERVICES - GENERAL PLANT WORK	5,535,863
14	TELECOM 2019 FUNDING PROJECT	5,056,219
15	IT DEMAND WORK FUNDING PROJECT	4,083,663
16	GENERIC CAPITAL COSTS	3,600,982
17	DEC MICROWAVE	3,161,872
18	PANASONIC UNITS - CAROLINAS WEST	2,868,698
19	GRIDWAN CORE ROUTER UPFIT	2,816,030
20	TELECOM MICROWAVE PROJECTS - NORTH CAROLINA	2,224,717
21	GRID WAN COMMUNICATIONS	2,158,432
22	NERC CIP COMPLIANCE - ROUTERS, SWITCHES, CARD READERS INSTALLATION	2,045,332
23	TOWERS, SHELTERS & POWER SUPPLIES	2,012,301
24	GRID SOLUTIONS PROJECT 1 CORES	1,761,546
25	CUSTOMER CONNECT	1,659,279
26	ON SITE GENERATION EQUIPMENT FOR PRYSMIAN CABLES AND SYSTEMS	1,605,501
27	CONTROL CENTER FACILITIES	1,413,458
28	SMARTGRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	1,237,861
29	ENERGY TECHNOLOGY SERVICE PD ALLOCATION	1,193,050
30	PROJECTS LESS THAN $1 MILLION	4,619,145
31	TOTAL GENERAL PLANT $126,837,757	
32		
33	INTANGIBLE PLANT	
34		
35	CUSTOMER CONNECT	45,581,824
36	SMARTGRID DEE DISTRIBUTED MANAGEMENT SYSTEM ADMS	22,759,423
37	IT DEMAND WORK FUNDING PROJECT	9,130,432
38	SMARTGRID DEE TRANSMISSION HEALTH RISK MANAGEMENT	7,226,930
39	CATAWBA WATEREE RELICENSING	6,122,731
40	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	5,549,213
41	SMARTGRID DISTRIBUTED MANAGEMENT SYSTEM ENHANCEMENTS	5,476,887
42	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	4,013,253
43	TOTAL	1,377,950,765

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	3,917,661
2	OCONEE CORE MONITORING SOFTWARE AND SERVERS	3,460,365
3	SMARTGIRD DISTRIBUTED MANAGEMENT SYSTEM CONSOLIDATION - TED THOMAS TOWER	3,084,915
4	SMARTGRID SECURE ACCESS AND DEVICE MANAGEMENT	2,218,215
5	ARCOS SYSTEM OUTAGE STAFFING PROJECT	2,195,679
6	ADVANCED DISTRIBUTION PLANNING TOOL	1,693,087
7	SMARTGRID DATA ANALYTICS (ASSET MANAGEMENT) - JESSICA BISHOP TOWER	1,597,773
8	REAL ESTATE SERVICES - MISCELLANEOUS CAROLINAS WEST - SOFTWARE PROJECTS	1,439,219
9	PROJECTS LESS THAN $1 MILLION	7,445,715
10	TOTAL INTANGIBLE PLANT $132,913,322	
11		
12	PRODUCTION PLANT	
13		
14	OCONEE MAIN STREAM ISOLATION VALVES	84,839,113
15	BELEWS CREEK DUAL FUEL COFIRING	79,630,650
16	MARSHALL NATURAL GAS ADDITION FOR WARMUP / COFIRING	39,545,801
17	OCONEE PLANT UNIT 1 LOW PRESSURE TURBINE	35,593,076
18	KEOWEE GENERATOR STATOR OVERHAUL	27,578,932
19	BAD CREEK UNIT 2 UPRATE PROJECT	25,847,650
20	MCGUIRE LICENSE RENEWAL	17,699,676
21	LINCOLN NEW COMBUSTION TURBINE UNIT	16,410,197
22	CEDAR CLIFF POWER HOUSE DAM INFLOW DESIGN FLOOD SPILLWAY & GATE HOUSE	16,182,873
23	LOOKOUT SHOALS PLANT - SEISMIC NET PROJECT	15,472,246
24	OCONEE SUPPLEMENTAL LICENSE REQUEST	13,975,298
25	MARSHALL STEAM PLANT SCR INSTALLATION	13,536,829
26	CLIFFSIDE UNIT 5 BIOREACTOR WASTE WATER TREATMENT	13,383,377
27	WYLIE PLANT UNIT 4 AERATING RUNNER	12,785,884
28	OCONEE UNIT 2 MEASUREMENT UNCERTAINTY RECAPTURE RATE	11,935,305
29	OCONEE SSF ELECTRICAL GENERATOR	11,663,427
30	OCONEE UNIT 1 MEASUREMENT UNCERTAINTY RECAPTURE RATE	11,424,777
31	OCONEE UNIT 1 LOW PRESSURE TURBINE	10,174,338
32	OCONEE UNIT 3 MEASUREMENT UNCERTAINTY RECAPTURE RATE	10,078,204
33	OCONEE UNIT 1 PLANT SSF LETDOWN LINE	9,098,599
34	CATAWBA UNIT 1 TURBINE STEAM PATH	8,649,623
35	OCONEE CYBER SECURITY MITIGATION SECURITY SYSTEMS	7,650,203
36	OCONEE UNIT 3 PLANT SSF LETDOWN LINE	7,546,412
37	MCGUIRE UNIT 2 MAIN POWER RELAYING	7,362,167
38	GASTON SOLAR	6,946,045
39	MAIDEN CREEK SOLAR	5,885,956
40	WATEREE PLANT UNIT 5 AERATING RUNNER	5,218,348
41	MCGUIRE UNIT 2 DISTRIBUTED CONTROL SYSTEM SERVER PROJECT	5,141,864
42	DEARBORN DIVERSION DAM STRUCTURAL MODIFICATIONS	4,913,710
43	TOTAL	1,377,950,765

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
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3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BAD CREEK UNIT 1 UPRATE	4,316,635
2	OCONEE UNIT 1 SSF INSTRUMENTATION AND TORNADO LICENSE AMENDMENT REQUEST	4,058,152
3	IT FUNDING PROJECT FOR NUCLEAR	4,007,780
4	SECURITY BREACH AND DEFENSIVE POSITIONS	3,823,321
5	BUCK COMBUSTION - INSTALL NEW RETENTION POND	3,626,488
6	OCONEE MAIN GENERATOR RELAY PANEL	3,600,273
7	DEVILS FORK STATE PARK DESIGNATED DRIVER ACCESS	3,374,211
8	MCGUIRE UNIT 1 & UNIT 2 POLAR CRANE METER & CONTROLS	3,257,923
9	OCONEE PLANT INSURABLE - MSIV ALT SSF INSTRUMENTATION U2	3,194,552
10	OCONEE PLANT INSURABLE - MNS CONTROL ROD PURCHASES	3,090,932
11	MOUNTIAN ISLAND - TRASH RACKS STOP LOGS SYSTEM	2,920,098
12	MCGUIRE PLANT ISFSI PHASE 4 TEMPERATURE MONITOR SYSTEM & SECURITY CAMERAS	2,743,474
13	CATAWBA UNIT 2 TURBINE STEAM PATH	2,678,431
14	OCONEE PLANT INSURABLE-ALLOY 600 COMPLEX NOZZLE U3SB	2,650,610
15	OCONEE UNIT 2 HPI MOTOR	2,421,877
16	OCONEE NUCLEAR STEAM NON-QA INVERTER-SECURITY EQUIPMENT	2,402,076
17	COAL HANDLING UNDERGROUND PIPE	2,359,297
18	MCGUIRE UNIT 1 GENERATOR STATOR REFURBISHMENT	2,329,311
19	MOUNTIAN ISLAND - TURBINE RUNNER	2,273,206
20	MOUNTAIN ISLAND DAM SEISMIC	2,240,213
21	MCGUIRE UNIT 2 ROTORK NA2 ACTUATOR	2,113,061
22	NUCLEAR ALERT & NOTIFICATION SYSTEM	1,984,711
23	WYLIE - TRASH RACKS STOP LOGS SYSTEM	1,976,839
24	TENNESSEE CREEK - MECHANICAL LIFE EXTENSION	1,964,408
25	JOCASSEE - EXTERIOR LIFE EXTENSION	1,905,618
26	FERC WATEREE MOLLEY CREEK PARK	1,858,256
27	MCGUIRE UNIT 1 RN SUCTION OVERPRESSURE PROTECTION SYSTEM	1,806,205
28	OCONEE NUCLEAR STEAM 3A & 3B LETDOWN COOLERS	1,635,552
29	CEDAR CREEK UNIT 1 GENERATOR STATOR & ROTOR REWIND	1,586,068
30	FERC KEOWEE TOXAWAY SHORELINE STAB	1,544,218
31	2018 DBAI BREAKER TO TECH SUPPORT CENTER	1,484,358
32	CATAWBA LICENSE RENEWAL	1,438,115
33	PRYSMIAN GROUP - FIBER PLANT AND CABLE PLANT	1,414,411
34	TENNESSEE CREEK TRANSFORMER & SWITCH	1,360,152
35	MARSHALL STEAM-FLY ASH SILO WATER SOURCE	1,339,428
36	SECURE OWNER CONTROLLED AREA	1,308,028
37	MARSHALL STEAM-POWER DIST SYSTEM FOR OUTAGES	1,297,167
38	TUCK TRASH RAKE/HEADGATE	1,258,373
39	JOCASSEE OCONEE 1X AUXILLARY TRANSFORMER	1,226,121
40	TENNESSEE CREEK GENERATOR STATOR REWIND	1,214,397
41	FERC HAGERS CREEK ACCESS AREA	1,145,008
42	TENNESSEE CREEK ELECTRICAL LIFE EXTENSION	1,071,774
43	TOTAL	1,377,950,765

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CONSTRUCTION WORK IN PROGRESS - - ELECTRIC (Account 107)

1. Report below descriptions and balances at end of year of projects in process of construction (107)
2. Show items relating to "research, development, and demonstration" projects last, under a caption Research, Development, and Demonstrating (see Account 107 of the Uniform System of Accounts)
3. Minor projects (5% of the Balance End of the Year for Account 107 or $1,000,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	BELEWS CREEK 2-PPT UPGRADE PROJECT	1,057,599
2	OCONEE NUCLEAR STEAM SITE SECURITY COMPUTER	1,015,575
3	BAD CREEK POWERHOUSE CHILLER	1,005,926
4	PROJECTS LESS THAN $1 MILLION	71,336,403
5	TOTAL PRODUCTION PLANT $705,887,211	
6		
7	TRANSMISSION PLANT	
8		
9	ORCHARD TIE - BUILD A 230KV TO 100KV STATION	34,359,501
10	RURAL HALL TIE STATIC VAR COMPENSATOR	26,693,767
11	LINCOLN CT #17 INTERCONNECTION	7,642,993
12	NORTH GREENSBORO TIE BANK 4	7,516,379
13	OAKBORO TIE RELAY	4,495,034
14	DUKE UNIV 44 KV UNDERGROUND SYSTEM	4,369,107
15	SPINDALE 44 KV LINE REBUILD	4,336,412
16	PEACH VALLEY TIE 230KV SERIES BJB	3,634,149
17	PLEASANT GARDEN 525KV BREAKERS	3,130,939
18	BU 20017 DEC TRANSMISSION SUBSTATIONS (FF) FUNDING PROJECT FOR ENABLE	2,850,400
19	MITCHELL RIVER SERIES BJB	2,489,253
20	ENO TIE ADD REDUNDANT RELAYS	1,949,080
21	WOODRUFF TIE - LINE RELAY TU'S	1,791,663
22	MARSHALL STEAM SWITCHYARD GAS BREAKERS	1,748,519
23	MCGUIRE NUCLEAR STATION-COWANS FORD BLACK & WHITE TRANSMISSION LINES	1,623,962
24	TRANSFORMER COOLER	1,446,391
25	BU 20017 DEC TRANSMISSION LINES (GG) FUNDING PROJECT FOR ENABLE	1,381,704
26	NORTH CAROLINA TRANSMISSION LINE INSULATOR - POLYMER	1,345,720
27	OCONEE NUCLEAR STEAM 525KV RELAY	1,241,936
28	RURAL HALL TIE SERIES BJB	1,102,858
29	ALBEMARLE SW STA 100KV BREAKERS	1,058,382
30	PLEASANT GARDEN SEC. ENHANCEMENT	1,054,300
31	BELTON TIE (1) OVERDUTIED BREAKER	1,036,036
32	OAKBORO TIE (2) 230KV BREAKERS	1,003,709
33	PROJECTS LESS THAN $1 MILLION	35,973,628
34	TOTAL TRANSMISSION PLANT $155,275,822	
35		
36		
37		
38		
39		
40		
41		
42		
43	TOTAL	1,377,950,765

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ACCUMULATED PROVISION FOR DEPRECIATION OF ELECTRIC UTILITY PLANT (Account 108)

1. Explain in a footnote any important adjustments during year.
2. Explain in a footnote any difference between the amount for book cost of plant retired, Line 11, column (c), and that reported for electric plant in service, pages 204-207, column 9d), excluding retirements of non-depreciable property.
3. The provisions of Account 108 in the Uniform System of accounts require that retirements of depreciable plant be recorded when such plant is removed from service. If the respondent has a significant amount of plant retired at year end which has not been recorded and/or classified to the various reserve functional classifications, make preliminary closing entries to tentatively functionalize the book cost of the plant retired. In addition, include all costs included in retirement work in progress at year end in the appropriate functional classifications.
4. Show separately interest credits under a sinking fund or similar method of depreciation accounting.

Section A. Balances and Changes During Year

Line No.	Item (a)	Total (c+d+e) (b)	Electric Plant in Service (c)	Electric Plant Held for Future Use (d)	Electric Plant Leased to Others (e)
1	Balance Beginning of Year	15,321,614,259	15,321,614,259		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	1,100,429,701	1,100,429,701		
4	(403.1) Depreciation Expense for Asset Retirement Costs	51,093	51,093		
5	(413) Exp. of Elec. Plt. Leas. to Others				
6	Transportation Expenses-Clearing	1,185,680	1,185,680		
7	Other Clearing Accounts				
8	Other Accounts (Specify, details in footnote):	89,276,482	89,276,482		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	1,190,942,956	1,190,942,956		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	299,989,615	299,989,615		
13	Cost of Removal	226,690,230	226,690,230		
14	Salvage (Credit)	110,118,217	110,118,217		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	416,561,628	416,561,628		
16	Other Debit or Cr. Items (Describe, details in footnote):	38,592,752	38,592,752		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	16,134,588,339	16,134,588,339		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	3,865,120,001	3,865,120,001		
21	Nuclear Production	3,591,096,132	3,591,096,132		
22	Hydraulic Production-Conventional	331,905,703	331,905,703		
23	Hydraulic Production-Pumped Storage	637,086,195	637,086,195		
24	Other Production	982,260,858	982,260,858		
25	Transmission	1,412,856,108	1,412,856,108		
26	Distribution	4,877,986,925	4,877,986,925		
27	Regional Transmission and Market Operation				
28	General	436,276,417	436,276,417		
29	TOTAL (Enter Total of lines 20 thru 28)	16,134,588,339	16,134,588,339		

FOOTNOTE DATA

Schedule Page: 219 Line No.: 8 Column: c

ABSAT Depr Deferral	17,332,968
Amortization of Deferred Depreciation Expense - SC	(1,474,216)
Buck and Bridgewater	(121,061)
Capital Lease Adjustment	5,945,302
Cliffside	(320,949)
CWDC Depr Deferral	421,209
Dan River	(95,040)
Defer depr expense on SC AMI meter	2,944,090
Grid Modernization Deferral	1,081,975
Lee CC Budgeted Deferral	(4,366,159)
McGuire Oconee	(75,108)
Meter Reporting	(1,627,006)
Mocksville and Monroe	306,321
NC Lee CC Deferral Amortization	(525,414)
NPL WWII assets	(75,977)
Renewables - Solar Deferral	686,849
Rotable Spares	(124,995)
SC Depr Deferral	3,790,842
SC Lee CC Deferral Amortization	(70,827)
SC Lee CC Depr Deferral	1,875,554
Storm Depreciation	418,087
TEP Transmission Disallowance	611,248
ARO Depr Exp Deferred	62,789,884
ARO Depr Expense (403.1) Not Deferred	(51,093)
TOTAL	$**89,276,482**

Schedule Page: 219 Line No.: 12 Column: c

This balance does not tie to Retirements reported by Pg 204 - 207 due to the following:

Intangible Plant Retirements (which hit reserve acct 111100) 1,544,874

Schedule Page: 219 Line No.: 16 Column: c

BU Transfer to 75111 D10 Dozier Asset	(443,322)
NC/SC Meter NBV Offset due to Early Retirement	39,151,779
Rotable Spare Transfer	833,995
Dan River, WS Lee, Buck Pre CPR In Service Adj	(1,811,388)
Belews and Clemson Lease Completion Adjustments	367,876
Gain/Loss Related to Assets Retired	493,813
TOTAL	**38,592,752**

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INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

1. Report below investments in Accounts 123.1, investments in Subsidiary Companies.
2. Provide a subheading for each company and List there under the information called for below. Sub - TOTAL by company and give a TOTAL in columns (e),(f),(g) and (h)
(a) Investment in Securities - List and describe each security owned. For bonds give also principal amount, date of issue, maturity and interest rate.
(b) Investment Advances - Report separately the amounts of loans or investment advances which are subject to repayment, but which are not subject to current settlement. With respect to each advance show whether the advance is a note or open account. List each note giving date of issuance, maturity date, and specifying whether note is a renewal.
3. Report separately the equity in undistributed subsidiary earnings since acquisition. The TOTAL in column (e) should equal the amount entered for Account 418.1.

Line No.	Description of Investment (a)	Date Acquired (b)	Date Of Maturity (c)	Amount of Investment at Beginning of Year (d)
1	The Eastover Companies	06/30/1970		
2	Common Stock + Investment in Sub Equity			8,282,949
3	Undistributed Earnings			-3,523,596
4	Advance (Open accounts)			
5	Subtotal The Eastover Companies			4,759,353
6				
7	Claiborne Energy Services, Inc.	03/01/1990		
8	Common Stock + Investment in Sub Equity			3,917,479
9	Undistributed Earnings			4,437,238
10	Advance (Open accounts)			
11	Subtotal Claiborne Energy Services, Inc.			8,354,717
12				
13				
14				
15				
16				
17	Mischarge to be Reclassed in 2019			11
18				
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23				
24				
25				
26				
27				
28				
29				
30				
31				
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36				
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38				
39				
40				
41				
42	Total Cost of Account 123.1 $ 0		TOTAL	13,114,081

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

4. For any securities, notes, or accounts that were pledged designate such securities, notes, or accounts in a footnote, and state the name of pledgee and purpose of the pledge.
5. If Commission approval was required for any advance made or security acquired, designate such fact in a footnote and give name of Commission, date of authorization, and case or docket number.
6. Report column (f) interest and dividend revenues form investments, including such revenues form securities disposed of during the year.
7. In column (h) report for each investment disposed of during the year, the gain or loss represented by the difference between cost of the investment (or the other amount at which carried in the books of account if difference from cost) and the selling price thereof, not including interest adjustment includible in column (f).
8. Report on Line 42, column (a) the TOTAL cost of Account 123.1

Equity in Subsidiary Earnings of Year (e)	Revenues for Year (f)	Amount of Investment at End of Year (g)	Gain or Loss from Investment Disposed of (h)	Line No.
				1
		8,282,949		2
		-3,523,596		3
				4
		4,759,353		5
				6
				7
		3,917,479		8
		4,437,238		9
				10
		8,354,717		11
				12
				13
				14
				15
				16
	-11			17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
				35
				36
				37
				38
				39
				40
				41
	-11	13,114,070		42

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MATERIALS AND SUPPLIES

1. For Account 154, report the amount of plant materials and operating supplies under the primary functional classifications as indicated in column (a); estimates of amounts by function are acceptable. In column (d), designate the department or departments which use the class of material.
2. Give an explanation of important inventory adjustments during the year (in a footnote) showing general classes of material and supplies and the various accounts (operating expenses, clearing accounts, plant, etc.) affected debited or credited. Show separately debit or credits to stores expense clearing, if applicable.

Line No.	Account (a)	Balance Beginning of Year (b)	Balance End of Year (c)	Department or Departments which Use Material (d)
1	Fuel Stock (Account 151)	220,760,888	230,172,338	Electric
2	Fuel Stock Expenses Undistributed (Account 152)			
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	445,279,495	545,423,130	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	212,345,132	150,684,128	Electric
8	Transmission Plant (Estimated)	7,860,493	9,166,153	Electric
9	Distribution Plant (Estimated)	16,741,171	16,386,343	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)			
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	682,226,291	721,659,754	
13	Merchandise (Account 155)			
14	Other Materials and Supplies (Account 156)	103,378	-4,049	
15	Nuclear Materials Held for Sale (Account 157) (Not applic to Gas Util)			
16	Stores Expense Undistributed (Account 163)	45,188,768	44,056,245	
17				
18				
19				
20	TOTAL Materials and Supplies (Per Balance Sheet)	948,279,325	995,884,288	

FOOTNOTE DATA

Schedule Page: 227 Line No.: 5 Column: b

5. Assigned To Construction

Production	$337,122,879
Transmission	36,305,042
Distribution	71,851,574
Total	$445,279,495

Schedule Page: 227 Line No.: 5 Column: c

5. Assigned To Construction

Production	$427,476,314
Transmission	44,382,653
Distribution	73,564,163
Total	$545,423,130

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	SO2 Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	1,322,867.00	425,369	138,060.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	3,254.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	17,410.00	3,424		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	1,308,711.00	421,945	138,060.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	4,130.00		4,130.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	4,130.00			
40	Balance-End of Year			4,130.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		138		
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
138,236.00		138,236.00		3,587,331.00		5,324,730.00	425,369	1
								2
								3
				138,236.00		141,490.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						17,410.00	3,424	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
138,236.00		138,236.00		3,725,567.00		5,448,810.00	421,945	29
								30
								31
								32
								33
								34
								35
4,130.00		4,130.00		107,380.00		123,900.00		36
				4,130.00		4,130.00		37
								38
						4,130.00		39
4,130.00		4,130.00		111,510.00		123,900.00		40
								41
								42
								43
					21		159	44
								45
								46

FOOTNOTE DATA

Schedule Page: 228 Line No.: 1 Column: b

Beginning balance includes allowances for Cross State Air Pollution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 18 Column: c

Does not include the $22,565,346 for renewable energy credits consumption expense represented in account 0509213.

Schedule Page: 228 Line No.: 29 Column: b

Ending balance includes allowances for Cross State Air Polution Rule and the Acid Rain Program.

Schedule Page: 228 Line No.: 29 Column: m

Does not include the $53,271,559 for renewable energy credits represented in account 0158120.

Schedule Page: 228 Line No.: 39 Column: b

Represents allowances withheld in 2019 sold at auction.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2)

1. Report below the particulars (details) called for concerning allowances.
2. Report all acquisitions of allowances at cost.
3. Report allowances in accordance with a weighted average cost allocation method and other accounting as prescribed by General Instruction No. 21 in the Uniform System of Accounts.
4. Report the allowances transactions by the period they are first eligible for use: the current year's allowances in columns (b)-(c), allowances for the three succeeding years in columns (d)-(i), starting with the following year, and allowances for the remaining succeeding years in columns (j)-(k).
5. Report on line 4 the Environmental Protection Agency (EPA) issued allowances. Report withheld portions Lines 36-40.

Line No.	NOx Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2020 No. (d)	2020 Amt. (e)
1	Balance-Beginning of Year	32,976.00	4,675	19,124.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	1,325.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9					
10					
11					
12					
13					
14					
15	Total				
16					
17	Relinquished During Year:				
18	Charges to Account 509	17,510.00	4,675		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22					
23					
24					
25					
26					
27					
28	Total				
29	Balance-End of Year	16,791.00		19,124.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)				
34	Gains				
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year				
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales				
40	Balance-End of Year				
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)				
45	Gains				
46	Losses				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Allowances (Accounts 158.1 and 158.2) (Continued)

6. Report on Lines 5 allowances returned by the EPA. Report on Line 39 the EPA's sales of the withheld allowances. Report on Lines 43-46 the net sales proceeds and gains/losses resulting from the EPA's sale or auction of the withheld allowances.
7. Report on Lines 8-14 the names of vendors/transferors of allowances acquire and identify associated companies (See "associated company" under "Definitions" in the Uniform System of Accounts).
8. Report on Lines 22 - 27 the name of purchasers/ transferees of allowances disposed of an identify associated companies.
9. Report the net costs and benefits of hedging transactions on a separate line under purchases/transfers and sales/transfers.
10. Report on Lines 32-35 and 43-46 the net sales proceeds and gains or losses from allowance sales.

2021		2022		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
19,124.00		19,124.00				90,348.00	4,675	1
								2
								3
				19,124.00		20,449.00		4
								5
								6
								7
								8
								9
								10
								11
								12
								13
								14
								15
								16
								17
						17,510.00	4,675	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
19,124.00		19,124.00		19,124.00		93,287.00		29
								30
								31
								32
								33
								34
								35
								36
								37
								38
								39
								40
								41
								42
								43
								44
								45
								46

FOOTNOTE DATA

Schedule Page: 229 Line No.: 18 Column: c

Does not include the $22,565,346 for renewable energy credits consumption expense represented in account 0509213.

Schedule Page: 229 Line No.: 29 Column: c

Does not include the $53,271,559 for renewable energy credits represented in account 0158120.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

EXTRAORDINARY PROPERTY LOSSES (Account 182.1)

Line No.	Description of Extraordinary Loss [Include in the description the date of Commission Authorization to use Acc 182.1 and period of amortization (mo, yr to mo, yr).] (a)	Total Amount of Loss (b)	Losses Recognised During Year (c)	WRITTEN OFF DURING YEAR		Balance at End of Year (f)
				Account Charged (d)	Amount (e)	
1						
2						
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
15						
16						
17						
18						
19						
20	TOTAL					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

UNRECOVERED PLANT AND REGULATORY STUDY COSTS (182.2)

Line No.	Description of Unrecovered Plant and Regulatory Study Costs [Include in the description of costs, the date of Commission Authorization to use Acc 182.2 and period of amortization (mo, yr to mo, yr)] (a)	Total Amount of Charges (b)	Costs Recognised During Year (c)	WRITTEN OFF DURING YEAR Account Charged (d)	WRITTEN OFF DURING YEAR Amount (e)	Balance at End of Year (f)
21	Lee Nuclear COLA - Wholesale		24,035,534	407	10,335,179	13,700,355
22	Auth - 10/22/2019					
23	Amort Period - 10/19 to 09/31					
24						
25	Lee Nuclear COLA - NC Retail		265,145,693	407/421	18,573,706	246,571,987
26	Auth - 10/22/2019					
27	Amort Period - 08/18 to 07/30					
28						
29	Lee Nuclear COLA - SC Retail		93,597,561	407/421	3,462,332	90,135,229
30	Auth - 10/22/2019					
31	Amort Period - 06/19 to 03/31					
32						
33	Buck/Riverbend Early Retired Plnt		21,392,113	407	5,033,438	16,358,675
34	Auth - 7/25/2019					
35	Amort Period - 10/15 to 03/23					
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47						
48						
49	TOTAL		404,170,901		37,404,655	366,766,246

FOOTNOTE DATA

Schedule Page: 230 Line No.: 21 Column: a

Page 230b Column (a) Lines 21, 25 and 29
Abbreviations used:
COLA - Construction and Operation License Application

Schedule Page: 230 Line No.: 25 Column: c

Page 230b Column (c) Lines 25, 29 and 33:

This is the unamortized 2018 ending balance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

Transmission Service and Generation Interconnection Study Costs

1. Report the particulars (details) called for concerning the costs incurred and the reimbursements received for performing transmission service and generator interconnection studies.
2. List each study separately.
3. In column (a) provide the name of the study.
4. In column (b) report the cost incurred to perform the study at the end of period.
5. In column (c) report the account charged with the cost of the study.
6. In column (d) report the amounts received for reimbursement of the study costs at end of period.
7. In column (e) report the account credited with the reimbursement received for performing the study.

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	State Studies	58,443	0561600		
3	Orka Holding - SIS	1,635	0561600		
4	Oconee Nuclear - SIS	1,316	0561600		
5	Iron Works - SIS	2,041	0561600		
6	Baileybead Solar - SIS	2,521	0561600		
7	Rutabaga Holding - SIS	2,149	0561600		
8	Oasis	238	0561600		
9	Anderson - SIS	640	0561600		
10	Blue Ridge Solar - SIS	653	0561600		
11	Jonesville PV1- SIS	113	0561600		
12	Fort Lawn - SIS	166	0561600		
13	Bradley Solar - SIS	2,485	0561600		
14	Perini Solar - SIS	469	0561600		
15	Catawba Nuclear - SIS	910	0561600		
16	Broad River - SIS	2,128	0561600		
17	Hartwell Solar - FEA	1,905	0561600		
18	Quail Holdings - FEA	1,293	0561600		
19	Rainey - SIS	767	0561600		
20	Broad River - FEA	1,207	0561600		
21	**Generation Studies**				
22	State Studies	(176)	0561700		
23	Buck Combined Cycle	2,146	0561700		
24	Mill Creek	2,410	0561700		
25	Stoneville PV 1 - SIS	1,950	0561700		
26	Fresh Air Energy II - FEA	143	0561700		
27	Mill Creek - FEA	1,827	0561700		
28	Birdeye Rutabata - FEA	113	0561700		
29	Corbets Solar - FEA	1,424	0561700		
30	NTE IV Solar - FEA	868	0561700		
31	Beefmaster Solar - FEA	113	0561700		
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Regulatory Asset Related to Income Taxes (Various)	464,514,060	13,619,356	282/283	24,008,860	454,124,556
2						
3						
4	Vacation Accrual	78,292,988	2,122,840			80,415,828
5	NCUC Docket No. E-7, Sub 774					
6						
7						
8	Extraordinary Repairs - Thorpe Rewind	28,365		545	16,208	12,157
9	Amortized over 25 years					
10	NCUC Docket No. E-13, Sub 166					
11						
12						
13	Retail portion - IRS Section 124 Asset Depreciation	1,774,997		403	75,977	1,699,020
14						
15						
16	Energy Efficiency Cost Recovery					
17	NCUC Docket No. E-7, Sub 1050	115,589,490		456	31,498,257	84,091,233
18	PSCSC Docket No. 2011-420-E	53,635,861		456	37,941,860	15,694,001
19						
20						
21	Renewable Energy and Energy Portfolio	3,966,492	4,080,094	407	2,302,798	5,743,788
22	NCUC Docket No. E-7, Sub 1052					
23	Standard Cost Deferral					
24						
25						
26	Pension Non-Qualified	4,585,351	733,347			5,318,698
27	NCUC Docket No. E-100, Sub 112					
28						
29						
30	Pension Qualified	576,278,985	2,418,730	Various	158,377,404	420,320,311
31	NCUC Docket No. E-100, Sub 112					
32						
33						
34	Interest Rate Swap					
35	NCUC Docket No. E-7, Sub 1026					
36	PSCSC Docket No. 2013-59-E	71,876,710	78,134,980	427	3,136,438	146,875,252
37						
38						
39	Natural Gas Hedging - MTM	20,063,623	24,804,298			44,867,921
40	NCUC Docket No. E-7, Sub 862					
41	NCUC Docket No. E-7, Sub 1006					
42	NCUC Docket No. E-7, Sub 1033					
43	PSCSC Docket No. 2015-95-E					
44	TOTAL	3,988,381,655	1,006,612,801		1,274,068,265	3,720,926,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Buck and Bridgewater Deferred Costs	5,165,125		Various	300,345	4,864,780
2	25 Year Amortization					
3	NCUC Docket No. E-7, Sub 999					
4	PSCSC Docket No. 2012-57-E					
5						
6						
7	Dan River & Cliffside 6 Deferred Costs	24,841,527		Various	526,810	24,314,717
8	Dan River - 4 year Amortization - NC					
9	Dan River - 39 Year Amortization - SC					
10	Cliffside 6 - 4 year Amortization - NC					
11	Cliffside 6 - 35 Year Amortization - SC					
12	NCUC Docket No. E-7, Sub 1029					
13	PSCSC Docket No. 2013-99-E					
14						
15						
16	McGuire and Oconee Deferred Costs	3,771,865		Various	98,220	3,673,645
17	McGuire - 4 Year Amortization - NC					
18	McGuire - 43 Year Amortization - SC					
19	Oconee - 28 Year Amortization - SC					
20	NCUC Docket No. E-7, Sub 1029					
21	PSCSC Docket No. 2013-99-E					
22						
23						
24	Nuclear Levelization	87,362,987	42,268,970	Various	62,138,051	67,493,906
25	18-24 Months Amortization					
26	NCUC Docket No. E-7, Sub 1026					
27	PSCSC Docket No. 2013-59-E					
28						
29						
30	Billing System Deferral	656,028				656,028
31	NCUC Docket No. E-7, Sub 1026					
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	3,988,381,655	1,006,612,801		1,274,068,265	3,720,926,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Rate Case Costs					
2	NC Rate Case Costs	7,297,260		928	982,160	6,315,100
3	NCUC Docket No. E-7, Sub 909					
4	NCUC Docket No. E-7, Sub 989					
5	NCUC Docket No. E-7, Sub 1146					
6	SC Rate Case Costs	1,169,232	1,383,608	928	187,292	2,365,548
7	PSCSC Docket No. 2009-226-E					
8	PSCSC Docket No. 2011-271-E, Order No. 2012-77					
9	PSCSC Docket No. 2018-319-E, Order No. 2019-323					
10						
11						
12						
13	Coal Ash Basin - ARO Deferral	895,295,601	307,302,059	108/403	479,111,376	723,486,284
14	NC Coal Ash Management Act of 2014					
15	Consent Agreement with SCDHEC					
16						
17						
18	Coal Ash Remediation Costs	363,772,365	167,226,234			530,998,599
19	PSCSC Docket No. 2016-196-E, Order No. 2016-490					
20	PSCSC Docket No. 2018-319-E, Order No. 2019-323					
21						
22						
23	Deferred Fuel					
24	NCUC Docket No. E-7, Sub 1033	112,102,432	50,925,124			163,027,556
25	PSCSC Docket No. 2014-3-E	83,678,513		557	24,713,929	58,964,584
26						
27						
28	NCUC Regulatory Fee	3,181,250		928	555,412	2,625,838
29	NCUC Docket No. M-100, Sub 142					
30						
31						
32	SC Distributed Energy Resource Program	39,394,070	4,009,072	407/229	41,221,732	2,181,410
33	PSCSC Docket No. 2015-3-E					
34						
35						
36	Rotable Fleet Spare	1,687,961	121,514			1,809,475
37	NCUC Docket No. E-7, Sub 986A					
38	PSCSC Docket No. 2015-293-E					
39						
40						
41						
42						
43						
44	TOTAL	3,988,381,655	1,006,612,801		1,274,068,265	3,720,926,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	Advanced Metering Infrastructure	132,450,524	49,102,225	Various	15,793,222	165,759,527
2	PSCSC Docket No. 2016-240-E					
3						
4						
5	Coal Ash Spend	465,841,624	87,624,804	407	111,861,066	441,605,362
6	NCUC Docket No. E-7, Sub 1146					
7	PSCSC Docket No. 2018-319-E, OrderNo. 2019-323					
8						
9						
10	Customer Connect					
11	NCUC Docket No. E-7, Sub 1146	11,012,710	12,571,775			23,584,485
12	PSCSC Docket No. 2018-207-E, OrderNo. 2018-552	3,285,172	1,863,643	407	620,164	4,528,651
13						
14	Lee COLA - Nuclear Retail Portion					
15	NCUC Docket No. E-7, Sub 1146	265,145,693	295,148	407/182.2	265,440,841	
16	PSCSC Docket No. 2018-319-E, OrderNo. 2019-323		5,191,685	407	5,191,685	
17						
18						
19	Lee Combined Cycle Deferrals					
20	NCUC Docket No. E-7, Sub 1146	8,513,713		Various	868,245	7,645,468
21	PSCSC Docket No. 2018-207-E, Order No. 2018-552	8,450,652	9,412,273	Various	237,339	17,625,586
22						
23						
24	Ash Basin Strategic Action Team (ABSAT)					
25	NCUC Docket No. E-7, Sub 1146	5,007,797	35,630,855			40,638,652
26	PSCSC Docket No. 2016-196-E, Order No. 2016-490	1,974,934	8,215,786	Various	848,785	9,341,935
27						
28						
29	Carolinas West Primary District Control Center	2,375,283	1,159,198	Various	84,427	3,450,054
30	PSCSC Docket No. 2018-207-E, Order No. 2018-552					
31						
32						
33	NC Solar Rebate Program	3,503,163	5,583,777	182	449,917	8,637,023
34	NCUC Docket No. E-7, Sub 1166					
35						
36						
37	CPRE Rider	445,740	407,245			852,985
38	NCUC Docket No. E-7, Sub 1170					
39						
40						
41						
42						
43						
44	TOTAL	3,988,381,655	1,006,612,801		1,274,068,265	3,720,926,191

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY ASSETS (Account 182.3)

1. Report below the particulars (details) called for concerning other regulatory assets, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 182.3 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	NC Coal Inventory Rider	91,560		456	53,893	37,667
2	NCUC Docket No. E-7, Sub 1146					
3						
4						
5	Cost of Removal Settlement					
6	NCUC Docket No. E-7, Sub 1146	57,145,120		407	2,042,113	55,103,007
7	PSCSC Docket No. 2018-319-E, OrderNo. 2019-323		43,703,230	407	766,339	42,936,891
8						
9						
10	Grid Deferral	3,154,594	5,383,618	Various	688,761	7,849,451
11	PSCSC Docket No. 2018-206-E, OrderNo. 2018-519					
12						
13						
14	Depreciation Deferral		8,917,467	Various	1,928,101	6,989,366
15	PSCSC Docket No. 2018-319-E, OrderNo. 2019-323					
16						
17	Hydro Loss Recovery					
18	NCUC Docket No. E-7, Sub 1181		23,705,146			23,705,146
19	PSCSC Docket No. 2018-281-E, OrderNo. 2019-474		8,366,677			8,366,677
20						
21						
22	SC HB3659 Implementation		328,023			328,023
23	South Carolina-2019-H3659					
24						
25	Other Deferred Costs	238		921	238	
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44	TOTAL	3,988,381,655	1,006,612,801		1,274,068,265	3,720,926,191

FOOTNOTE DATA

Schedule Page: 232 Line No.: 30 Column: d

128, 186, 253, 926

Schedule Page: 232.1 Line No.: 1 Column: d

403,407,408,421,431

Schedule Page: 232.1 Line No.: 7 Column: d

403,407,408,421,431

Schedule Page: 232.1 Line No.: 16 Column: d

403,407,421,431

Schedule Page: 232.1 Line No.: 24 Column: d

510,513,517,519,520,523,524,528,529,530,531,532,921,930

Schedule Page: 232.3 Line No.: 1 Column: d

403,407,408

Schedule Page: 232.3 Line No.: 20 Column: d

403,407,408

Schedule Page: 232.3 Line No.: 21 Column: d

403,407,408

Schedule Page: 232.3 Line No.: 26 Column: d

403,407,421

Schedule Page: 232.3 Line No.: 29 Column: d

403,407,421

Schedule Page: 232.4 Line No.: 10 Column: d

403,407,408

Schedule Page: 232.4 Line No.: 14 Column: d

403,407,430

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS DEFFERED DEBITS (Account 186)

1. Report below the particulars (details) called for concerning miscellaneous deferred debits.
2. For any deferred debit being amortized, show period of amortization in column (a)
3. Minor item (1% of the Balance at End of Year for Account 186 or amounts less than $100,000, whichever is less) may be grouped by classes.

Line No.	Description of Miscellaneous Deferred Debits (a)	Balance at Beginning of Year (b)	Debits (c)	CREDITS Account Charged (d)	CREDITS Amount (e)	Balance at End of Year (f)
1	Demand Side Management Costs	-4,814,931	4,008,727			-806,204
2						
3	Storm Costs	147,910,351	30,541,001			178,451,352
4						
5	Renewables	-2,349,243		Various	452,641	-2,801,884
6						
7	I&D Insurance Receivable	739,450,276	20,042,739	131	17,251,637	742,241,378
8						
9	Pension Settlement Charges		52,947,719	926, 182	2,150,422	50,797,297
10						
11	Lee COLA - SC Retail Portion	93,597,561		182	93,597,561	
12						
13	Lee COLA - Wholesale Portion	24,035,534		182	24,035,534	
14						
15	Equity Return on BPM Sharing	691,300		421	150,809	540,491
16						
17	Combustion Turbine Generator	14,226,027		Various	7,012,671	7,213,356
18						
19	Retired Plant Cost	21,392,114		182,403	21,392,114	
20						
21	Pooled Inventory	4,534,508				4,534,508
22						
23	Costs Removal Retail Mitigation	48,588,842		182	48,588,842	
24						
25	Natural Gas Pipeline Upgrade	736,917		547	106,542	630,375
26						
27	Miscellaneous	98,330	433,700			532,030
28						
29						
30						
31						
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45						
46						
47	Misc. Work in Progress	1,092,095				-19,621
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)	2,273,257	3,905,012			6,178,269
49	TOTAL	1,091,462,938				987,491,347

FOOTNOTE DATA

Schedule Page: 233 Line No.: 5 Column: d

403,408,421,431

Schedule Page: 233 Line No.: 17 Column: d

548,549,552,554

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes.
2. At Other (Specify), include deferrals relating to other income and deductions.

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2			
3			
4			
5			
6			
7	Other	2,697,261,240	3,270,273,770
8	TOTAL Electric (Enter Total of lines 2 thru 7)	2,697,261,240	3,270,273,770
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)		
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	2,697,261,240	3,270,273,770

Notes

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204)

1. Report below the particulars (details) called for concerning common and preferred stock at end of year, distinguishing separate series of any general class. Show separate totals for common and preferred stock. If information to meet the stock exchange reporting requirement outlined in column (a) is available from the SEC 10-K Report Form filing, a specific reference to report form (i.e., year and company title) may be reported in column (a) provided the fiscal years for both the 10-K report and this report are compatible.
2. Entries in column (b) should represent the number of shares authorized by the articles of incorporation as amended to end of year.

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1				
2				
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

3. Give particulars (details) concerning shares of any class and series of stock authorized to be issued by a regulatory commission which have not yet been issued.
4. The identification of each class of preferred stock should show the dividend rate and whether the dividends are cumulative or non-cumulative.
5. State in a footnote if any capital stock which has been nominally issued is nominally outstanding at end of year.
Give particulars (details) in column (a) of any nominally issued capital stock, reacquired stock, or stock in sinking and other funds which is pledged, stating name of pledgee and purposes of pledge.

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
						1
						2
						3
						4
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER PAID-IN CAPITAL (Accounts 208-211, inc.)

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.

(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.

(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.

(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.

(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1		
2	Account 208	
3	None	
4		
5		
6		
7	Account 209	
8	None	
9		
10		
11		
12	Account 210	
13	None	
14		
15		
16		
17	Account 211	
18	Balance January 1, 2019	3,725,067,453
19		
20		
21		
22	Equitization of Intercompany Receivables	
23		
24		
25		
26	Common Stock	
27		
28		
29		
30	Equity Infusion from Duke Energy Corporation	
31		
32		
33		
34	Other Misc Paid-in Capital	
35		
36		
37		
38		
39		
40	TOTAL	3,725,067,453

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

CAPITAL STOCK EXPENSE (Account 214)

1. Report the balance at end of the year of discount on capital stock for each class and series of capital stock.
2. If any change occurred during the year in the balance in respect to any class or series of stock, attach a statement giving particulars (details) of the change. State the reason for any charge-off of capital stock expense and specify the account charged.

Line No.	Class and Series of Stock (a)	Balance at End of Year (b)
1		
2		
3		
4		
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19		
20		
21		
22	TOTAL	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1	Account 221:		
2	----------		
3	First and Refunding Mortgage Bonds:		
4			
5	6.00% Series	300,000,000	57,500
6			3,696,000 D
7			
8	8.95% Series	15,994,025	21,967
9			
10	3.75% First Mortgage Bonds	500,000,000	4,447,400
11			4,170,000 D
12			
13	6.45% Senior Unsecured Notes	350,000,000	2,541,747
14			2,161,255 D
15			
16	2.5% First Mortgage Bonds	500,000,000	2,387,692
17			195,000 D
18			
19	3.875% First Mortgage Bonds	500,000,000	4,137,692
20			1,765,000 D
21			
22	6.1% Senior Unsecured Notes	500,000,000	3,817,772
23			65,000 D
24			
25	2.95% First Mortgage Bonds	600,000,000	3,205,303
26			1,452,000 D
27			
28	6.00% First Mortgage Bonds	500,000,000	4,109,714
29			350,000 D
30			
31	6.05% First Mortgage Bonds	600,000,000	4,686,704
32			1,650,000 D
33	TOTAL	11,818,002,544	106,657,299

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			
2	5.3% First Mortgage Bonds	750,000,000	5,993,147
3			3,202,500 D
4			
5	4.3% First Mortgage Bonds	450,000,000	2,112,010
6			1,057,500 D
7			
8	3.9% First Mortgage Bonds	500,000,000	2,780,050
9			510,000 D
10			
11	4.25% First Mortgage Bonds	650,000,000	5,297,322
12			1,098,500 D
13			
14	4.00% First Mortgage Bonds	650,000,000	5,556,082
15			5,174,000 D
16			
17	3.70% First Mortgage Bonds	550,000,000	4,637,612
18			803,000 D
19			
20	3.05% First Mortgage Bonds	500,000,000	2,191,354
21			585,000 D
22			
23	3.95% First Mortgage Bonds	500,000,000	4,192,354
24			2,365,000 D
25			
26	3.35% First Mortgage Bonds	350,000,000	345,641
27			129,500 D
28			
29	3.95% First Mortgage Bonds	650,000,000	616,190
30			2,398,500 D
31			
32	2.45% First Mortgage Bonds	450,000,000	323,758
33	TOTAL	11,818,002,544	106,657,299

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224)

1. Report by balance sheet account the particulars (details) concerning long-term debt included in Accounts 221, Bonds, 222, Reacquired Bonds, 223, Advances from Associated Companies, and 224, Other long-Term Debt.
2. In column (a), for new issues, give Commission authorization numbers and dates.
3. For bonds assumed by the respondent, include in column (a) the name of the issuing company as well as a description of the bonds.
4. For advances from Associated Companies, report separately advances on notes and advances on open accounts. Designate demand notes as such. Include in column (a) names of associated companies from which advances were received.
5. For receivers, certificates, show in column (a) the name of the court -and date of court order under which such certificates were issued.
6. In column (b) show the principal amount of bonds or other long-term debt originally issued.
7. In column (c) show the expense, premium or discount with respect to the amount of bonds or other long-term debt originally issued.
8. For column (c) the total expenses should be listed first for each issuance, then the amount of premium (in parentheses) or discount. Indicate the premium or discount with a notation, such as (P) or (D). The expenses, premium or discount should not be netted.
9. Furnish in a footnote particulars (details) regarding the treatment of unamortized debt expense, premium or discount associated with issues redeemed during the year. Also, give in a footnote the date of the Commission's authorization of treatment other than as specified by the Uniform System of Accounts.

Line No.	Class and Series of Obligation, Coupon Rate (For new issue, give commission Authorization numbers and dates) (a)	Principal Amount Of Debt issued (b)	Total expense, Premium or Discount (c)
1			553,500 D
2			
3	3.20% First Mortgage Bonds	350,000,000	260,546
4			938,000 D
5			
6			
7			D
8			
9	Bonds issued through Medium Term Notes Facility:		
10	Accounts 222 and 223:		
11	----------		
12	Duke Energy Corporation - 1.9165%	300,000,000	
13			
14	Account 224:		
15	----------		
16			
17	Pollution Control 2006A - 4.375% fixed	71,605,000	1,393,412
18			
19	Pollution Control 2006B - 4.375% fixed	71,595,000	1,354,512
20			
21	Pollution Control 2008A - 4.625% fixed	50,000,000	1,143,326
22			
23	Pollution Control 2008B - 4.625% fixed	50,000,000	1,264,318
24			
25	Charlotte Metro Tower	68,695,987	
26			
27	Other Long Term Debt	490,112,532	3,462,919
28			
29			
30			
31			
32			
33	TOTAL	11,818,002,544	106,657,299

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
12/04/1998	12/01/2028	12/1998	12/2028	300,000,000	18,000,000	5
						6
						7
07/01/1991	07/01/2027	07/1991	07/2027	8,317,678	774,186	8
						9
03/12/2015	06/01/2045	03/2015	06/2045	500,000,000	18,750,000	10
						11
						12
10/08/2002	10/15/2032	10/2002	10/2032	350,000,000	22,575,000	13
						14
						15
03/11/2016	03/15/2023	03/2016	03/2023	500,000,000	12,500,000	16
						17
						18
03/11/2016	03/15/2046	03/2016	03/2046	500,000,000	19,375,000	19
						20
						21
06/05/2007	06/01/2037	06/2007	06/2037	500,000,000	30,500,000	22
						23
						24
11/17/2016	12/01/2026	12/2016	12/2026	600,000,000	17,700,000	25
						26
						27
01/10/2008	01/15/2038	01/2008	01/2038	500,000,000	30,000,000	28
						29
						30
04/14/2008	04/15/2038	04/2008	04/2038	600,000,000	36,300,000	31
						32
				11,799,816,144	486,691,902	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
11/16/2009	02/15/2040	11/2009	02/2040	750,000,000	39,750,000	2
						3
						4
06/02/2010	06/15/2020	06/2010	06/2020	450,000,000	19,350,000	5
						6
						7
05/19/2011	06/15/2021	05/2011	06/2021	500,000,000	19,500,000	8
						9
						10
12/08/2011	12/15/2041	12/2011	12/2041	650,000,000	27,625,000	11
						12
						13
09/21/2012	09/30/2042	09/2012	09/2042	650,000,000	26,000,000	14
						15
						16
11/14/2017	12/01/2047	11/2017	12/2047	550,000,000	20,350,000	17
						18
						19
03/01/2018	03/15/2023	03/2018	03/2023	500,000,000	15,250,000	20
						21
						22
03/01/2018	03/15/2048	03/2018	03/2048	500,000,000	19,750,000	23
						24
						25
11/08/2018	05/15/2022	11/2018	05/2022	350,000,000	11,725,000	26
						27
						28
11/08/2018	11/15/2028	11/2018	11/2028	650,000,000	25,675,000	29
						30
						31
08/15/2019	08/15/2029	08/2019	08/2029	450,000,000	4,195,625	32
				11,799,816,144	486,691,902	33

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

LONG-TERM DEBT (Account 221, 222, 223 and 224) (Continued)

10. Identify separate undisposed amounts applicable to issues which were redeemed in prior years.
11. Explain any debits and credits other than debited to Account 428, Amortization and Expense, or credited to Account 429, Premium on Debt - Credit.
12. In a footnote, give explanatory (details) for Accounts 223 and 224 of net changes during the year. With respect to long-term advances, show for each company: (a) principal advanced during year, (b) interest added to principal amount, and (c) principle repaid during year. Give Commission authorization numbers and dates.
13. If the respondent has pledged any of its long-term debt securities give particulars (details) in a footnote including name of pledgee and purpose of the pledge.
14. If the respondent has any long-term debt securities which have been nominally issued and are nominally outstanding at end of year, describe such securities in a footnote.
15. If interest expense was incurred during the year on any obligations retired or reacquired before end of year, include such interest expense in column (i). Explain in a footnote any difference between the total of column (i) and the total of Account 427, interest on Long-Term Debt and Account 430, Interest on Debt to Associated Companies.
16. Give particulars (details) concerning any long-term debt authorized by a regulatory commission but not yet issued.

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	AMORTIZATION PERIOD Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
08/15/2019	08/15/2049	08/2019	08/2049	350,000,000	4,262,222	3
						4
						5
						6
						7
						8
						9
						10
						11
10/2008	2099			300,000,000	18,214,465	12
						13
						14
						15
						16
09/01/2010	10/01/2031	09/2010	10/2031	71,605,000	3,132,719	17
						18
09/01/2010	10/01/2031	09/2010	10/2031	71,595,000	3,132,282	19
						20
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,501	21
						22
09/01/2010	11/01/2040	09/2010	11/2040	50,000,000	2,312,500	23
						24
12/23/2019	12/01/2052	01/2020	12/2052	68,695,987		25
						26
				479,602,479	17,680,402	27
						28
						29
						30
						31
						32
				11,799,816,144	486,691,902	33

FOOTNOTE DATA

Schedule Page: 256.2 Line No.: 12 Column: a

The interest rate varies on this intercompany loan. The interest rate is as of December 31, 2019.

Schedule Page: 256.2 Line No.: 27 Column: a

The Other Long Term Debt ending balance includes gains on cancelled swaps of $4.6 million as of December 31, 2019. The 2019 amortization of these gains was a credit of ($0.5) million to account number 427.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

RECONCILIATION OF REPORTED NET INCOME WITH TAXABLE INCOME FOR FEDERAL INCOME TAXES

1. Report the reconciliation of reported net income for the year with taxable income used in computing Federal income tax accruals and show computation of such tax accruals. Include in the reconciliation, as far as practicable, the same detail as furnished on Schedule M-1 of the tax return for the year. Submit a reconciliation even though there is no taxable income for the year. Indicate clearly the nature of each reconciling amount.
2. If the utility is a member of a group which files a consolidated Federal tax return, reconcile reported net income with taxable net income as if a separate return were to be field, indicating, however, intercompany amounts to be eliminated in such a consolidated return. State names of group member, tax assigned to each group member, and basis of allocation, assignment, or sharing of the consolidated tax among the group members.
3. A substitute page, designed to meet a particular need of a company, may be used as Long as the data is consistent and meets the requirements of the above instructions. For electronic reporting purposes complete Line 27 and provide the substitute Page in the context of a footnote.

Line No.	Particulars (Details) (a)	Amount (b)
1	Net Income for the Year (Page 117)	1,402,188,500
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20	See Notes for Detailed List	561,362,443
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	840,826,057
28	Show Computation of Tax:	
29	21% of $840,826,057	176,573,472
30	Prior Year Federal Tax Adjustments - Primarily Prior Year Tax True-Ups	-11,292,334
31		
32		
33	Total Federal Income Tax	165,281,138
34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		

FOOTNOTE DATA

Schedule Page: 261 Line No.: 20 Column: b

AFUDC Equity Income	41,617,164
AFUDC Interest	30,415,605
Benefits Accruals	126,121,273
Book Depreciation	(1,261,181,207)
Charitable Contribution Carryovers/Accruals	7,227,619
Coal Ash Spend, Net of Capitalized Portion	34,084,717
Contributions in Aid of Construction	(53,631,402)
COR Settlement	(7,694,065)
Cost of Removal	150,349,501
Deferred Fuel	26,211,195
End of Life Nuclear Fuel Cost Reserve	(14,795,433)
Equipment/T&D Repairs	407,600,000
Impairment	(11,888,869)
Injuries & Damages Accrual	32,859,485
Investment Tax Credit Amortization	4,229,734
Lawsuit Contingency	6,778,306
Lease Adjustments	11,113,146
Lee Unrecovered Plant	(117,633,094)
Loss on Reacquired Debt	(6,441,077)
Meals & Entertainment	(5,400,000)
Net Operating Loss Utilization/Deferral	39,968,800
Non-Cash Overhead Basis Adjustment	7,583,258
Non-Qualified Nuclear Decommissioning Contributions/Earnings	1,017,077
Nuclear Fuel Book Burned	(270,484,487)
Nuclear Insurance Reserve	(12,882,844)
Other	406,494
Plant License Renewal	4,612,655
Provision for Current Federal Income Taxes	(165,281,137)
Provision for Current State Income Taxes	700,475
Provision for Deferred Income Taxes	(137,087,273)
Rate Refunds	46,431,633
Regulatory Asset – ABSAT	42,997,856
Regulatory Asset – AMI/Non-AMI Meters	33,309,003
Regulatory Asset – Customer Connect	13,815,254
Regulatory Asset – Deferred Plant Costs	(5,033,631)
Regulatory Asset – Depreciation Deferral	6,989,366
Regulatory Asset – Energy Efficiency	(69,440,117)
Regulatory Asset – FAS 158	(107,774,058)
Regulatory Asset – Grid Deferred Costs	4,694,857
Regulatory Asset – Hydro Impairment	32,071,823
Regulatory Asset – Lee CC Deferred Costs	8,306,689
Regulatory Asset – Nuclear COLA	85,261,879
Regulatory Asset – Nuclear Levelization	(19,869,081)
Regulatory Asset – Rate Case Expenses	4,119,168

FOOTNOTE DATA

Regulatory Asset – Solar Rebate Program	5,133,859
Regulatory Liability - Job Retention Rider	(20,502,740)
Return on Solar Assets	(6,070,749)
SC Distributive Energy Resource Program	(37,212,660)
Section 263A Adjustment	83,200,000
Self Developed Software	64,326,771
Severance Accrual	88,855,819
Storm Cost Deferral	36,835,293
Storm Cost Reserves	(15,117,213)
Tax Depreciation	1,405,374,950
Tax Gain/Loss	51,000,000
Tax Interest Capitalized	(38,837,144)
Total	561,362,443

INSTRUCTION 2

Allocations of consolidated tax liability are based on the percentage method of allocation under Treasury Regulation Section 1.1502-33(d)(3), with a fixed percentage of 100 percent, in conjunction with the income method under Treasury Regulation Section 1.1552-1(a)(1).

For members of the affiliated group, see corporations controlled by respondent, page 103.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR

1. Give particulars (details) of the combined prepaid and accrued tax accounts and show the total taxes charged to operations and other accounts during the year. Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged. If the actual, or estimated amounts of such taxes are know, show the amounts in a footnote and designate whether estimated or actual amounts.
2. Include on this page, taxes paid during the year and charged direct to final accounts, (not charged to prepaid or accrued taxes.) Enter the amounts in both columns (d) and (e). The balancing of this page is not affected by the inclusion of these taxes.
3. Include in column (d) taxes charged during the year, taxes charged to operations and other accounts through (a) accruals credited to taxes accrued, (b)amounts credited to proportions of prepaid taxes chargeable to current year, and (c) taxes paid and charged direct to operations or accounts other than accrued and prepaid tax accounts.
4. List the aggregate of each kind of tax in such manner that the total tax for each State and subdivision can readily be ascertained.

Line No.	Kind of Tax (See instruction 5) (a)	BALANCE AT BEGINNING OF YEAR Taxes Accrued (Account 236) (b)	Prepaid Taxes (Include in Account 165) (c)	Taxes Charged During Year (d)	Taxes Paid During Year (e)	Adjust-ments (f)
1						
2	NORTH CAROLINA					
3	STATE					
4	Franchise	2,289,610		22,084,639	14,206,761	-243,594
5	Unemployment	2,189		96,720	97,553	
6	Miscellaneous			191,850	191,850	
7	Income taxes	-1,900,791		7,675,144	5,135,931	-2,539,212
8						
9	LOCAL					
10	Property 2019	26,228,959	3,558,722	93,230,994	119,069,538	-354,725
11						
12						
13						
14	SOUTH CAROLINA					
15	STATE					
16	Franchise	1,067,614		7,837,568	12,825,845	
17	Unemployment	1,395		179,109	2,372,049	
18	Kilowatt hour	653,510		9,908,012	9,736,737	
19	Miscellaneous			763	763	
20	Income Taxes	3,873,932		4,899,279	9,144,695	3,215,632
21						
22	LOCAL					
23	Property 2019	116,339,611		113,732,249	219,137,622	-445,397
24						
25						
26	OTHER STATES					
27	Unemployment	1,234		12,622	11,598	
28						
29	FEDERAL					
30	Social Security	9,411,212		42,402,879	44,369,297	1,856,950
31	Unemployment	7,815		1,159,798	440,004	-720,765
32	Highway Use			83,600	83,600	
33	Income taxes	6,296,444		165,281,137	100,027,057	-61,838,097
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	164,272,734	3,558,722	468,776,363	536,850,900	-61,069,208

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

5. If any tax (exclude Federal and State income taxes)- covers more then one year, show the required information separately for each tax year, identifying the year in column (a).
6. Enter all adjustments of the accrued and prepaid tax accounts in column (f) and explain each adjustment in a foot- note. Designate debit adjustments by parentheses.
7. Do not include on this page entries with respect to deferred income taxes or taxes collected through payroll deductions or otherwise pending transmittal of such taxes to the taxing authority.
8. Report in columns (i) through (l) how the taxes were distributed. Report in column (l) only the amounts charged to Accounts 408.1 and 409.1 pertaining to electric operations. Report in column (l) the amounts charged to Accounts 408.1 and 109.1 pertaining to other utility departments and amounts charged to Accounts 408.2 and 409.2. Also shown in column (l) the taxes charged to utility plant or other balance sheet accounts.
9. For any tax apportioned to more than one utility department or account, state in a footnote the basis (necessity) of apportioning such tax.

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
						2
						3
9,923,894		22,084,639				4
1,356		96,720				5
		191,850				6
-1,900,790		7,961,893			-286,749	7
						8
						9
-18,653	3,504,379	90,605,500			2,625,494	10
						11
						12
						13
						14
						15
-3,920,663		7,837,568				16
-2,191,545		179,109				17
824,785		9,908,012				18
		724			39	19
2,844,148		5,101,633			-202,354	20
						21
						22
10,488,841		113,451,135			281,114	23
						24
						25
						26
2,258		12,622				27
						28
						29
9,301,744		42,402,879				30
6,844		1,159,798				31
		83,600				32
9,712,427		170,708,943			-5,427,806	33
						34
						35
						36
						37
						38
						39
						40
35,074,646	3,504,379	471,786,625			-3,010,262	41

FOOTNOTE DATA

Schedule Page: 262 Line No.: 1 Column: a

North Carolina utility franchise tax was repealed on 7/1/14.

South Carolina license fee is based on revenues and property.

State unemployment taxes and Federal social security taxes are allocated on the basis of wage and salary expenditures.

South Carolina kilowatt hour tax is based on the sales of electric energy and is therefore charged entirely to the electric department.

Income taxes applicable to electric operations are calculated on electric operating income adjusted to a current tax basis and reduced by electric's share of interest expense (taxable income). Federal income tax is the product of taxable income less state income taxes at the statutory rate of 21%. North Carolina income tax is the product of taxable income apportioned to North Carolina on a stand-alone basis at the statutory rate of 2.5%. South Carolina income tax is the product of taxable income apportioned to South Carolina on a stand-alone basis at the statutory rate of 5%.

Miscellaneous taxes are allocated according to the nature of the tax consistent with the bases stated above.

Property (ad velorem) taxes are charged to a central business unith within Duke Energy Carolinas.

Municipal and state privilege licenses are charged to the department which originate taxable revenue or engage in taxable activity.

Per the instructions for page 262-263, which state, "Do not include gasoline and other sales taxes which have been charged to the accounts to which the taxed material was charged", the following amounts have been excluded from Taxes Accrued balances:
Sales and Use Tax Payable - 6,154,539 excluded from Balance At Beginning Of Year(column b)
Sales and Use Tax Payable - 7,364,757 exlcuded from Balance At End Of Year(column g)

Schedule Page: 262 Line No.: 4 Column: f

Offset to account 186	$(245,209)
Offset to account 253	1,615
Total	$(243,594)

Schedule Page: 262 Line No.: 7 Column: f

Offset to account 146

Schedule Page: 262 Line No.: 10 Column: f

Offset to account 146	$(271,960)
Offset to account 151	297,327
Offset to account 182	(51,123)
Offset to account 253	(51,537)
Offset to account 419	(277,432)
Total	$(354,725)

FOOTNOTE DATA

Schedule Page: 262 Line No.: 20 Column: f

Offset to account 146

Schedule Page: 262 Line No.: 23 Column: f

Offset to account 146	$(562,893)
Offset to account 182	117,496
Total	$(445,397)

Schedule Page: 262 Line No.: 30 Column: f

Offset to account 143	$1,777,422
Offset to account 182	159,588
Offset to account 242	(115,045)
Offset to account 456	34,985
Total	$1,856,950

Schedule Page: 262 Line No.: 31 Column: f

Offset to account 242

Schedule Page: 262 Line No.: 33 Column: f

Offset to account 143	$2,587,106
Offset to account 146	(56,308,467)
Offset to account 190	(8,116,736)
Total	$(61,838,097)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

Report below information applicable to Account 255. Where appropriate, segregate the balances and transactions by utility and nonutility operations. Explain by footnote any correction adjustments to the account balance shown in column (g).Include in column (i) the average period over which the tax credits are amortized.

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%	1,446,870			411.4	71,225	
4	7%						
5	10%	56,341,810			411.4	4,158,509	
6	15%	125,000,000					
7	30%	48,581,139	190	3,845,302			85,098
8	TOTAL	231,369,819		3,845,302		4,229,734	85,098
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11	TOTAL						
12							
13							
14							
15							
16							
17							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255) (continued)

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
1,375,645			3
			4
52,183,301			5
125,000,000			6
52,511,539			7
231,070,485			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
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			45
			46
			47
			48

FOOTNOTE DATA

Schedule Page: 266 Line No.: 5 Column: b

The 10% amounts for electric utility contain ITC that was calculated at 8% of the basis value. This is a result of the Company's election under IRC Code Section 48(q)(4) which allows a company to calculate ITC at 10% with a basis reduction or at 8% with no basis reduction.

The amount included in electric utility at 8% is:

Balance at beginning of year	$9,444,050
Allocations to current year's income	$(700,124)
Balance at end of year	$8,743,926

Schedule Page: 266 Line No.: 6 Column: b

Eligible ITC for progress expenditures at the Cliffside Plant. Placed in service date 2012. Tax Credit is 15% with $125M cap for the entire project.

Schedule Page: 266 Line No.: 7 Column: b

Eligible 30% ITC for expenditures for the Mocksville Solar, Monroe Solar, Bear Creek Hydro, Cowans Ford Hydro, and Oxford Hydro projects. Placed in service dates 2016-2018.

Schedule Page: 266 Line No.: 7 Column: d

Eligible 30% ITC for expenditures for the Woodleaf Solar project. Placed in service date 2018.

Schedule Page: 266 Line No.: 7 Column: g

During 2019, the 2018 Federal Tax Return was filed and an additional ITC of $85,098, related to the Monroe Solar project, was claimed on the tax return. The Monroe Solar project was originally reported on this page in 2017, and then trued up on the 2018 page, for a total of $34,040,092 related to the Monroe Solar project in the ending balance on the 30% row of this page.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER DEFFERED CREDITS (Account 253)

1. Report below the particulars (details) called for concerning other deferred credits.
2. For any deferred credit being amortized, show the period of amortization.
3. Minor items (5% of the Balance End of Year for Account 253 or amounts less than $100,000, whichever is greater) may be grouped by classes.

Line No.	Description and Other Deferred Credits (a)	Balance at Beginning of Year (b)	DEBITS Contra Account (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Year (f)
1						
2	Decommissioning Costs	425,168,043			96,488,505	521,656,548
3						
4	Prepaid Extra Facilities Lighting	14,465,971	454	5,363,713	2,634,759	11,737,017
5						
6	Merger Rel Charitable Contrib	11,900,000	426	11,900,000		
7						
8	Def NC Tax Rate Change	87,003,245	254	87,003,245		
9						
10	Catawba - Wateree relicensing	7,456,869	146	559,957		6,896,912
11						
12	Manufactured Gas Plants	7,875,000			240,000	8,115,000
13						
14	JEA Option Agreement	7,500,000				7,500,000
15						
16	Deferred Debt Return - Solar	6,569,101			296,210	6,865,311
17						
18	Other	5,453,952		75,385	5,216,158	10,594,725
19						
20						
21						
22						
23						
24						
25						
26						
27						
28						
29						
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42						
43						
44						
45						
46						
47	TOTAL	573,392,181		104,902,300	104,875,632	573,365,513

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - ACCELERATED AMORTIZATION PROPERTY (Account 281)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to amortizable property.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Accelerated Amortization (Account 281)			
2	Electric			
3	Defense Facilities			
4	Pollution Control Facilities			
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)			
9	Gas			
10	Defense Facilities			
11	Pollution Control Facilities			
12	Other (provide details in footnote):			
13				
14				
15	TOTAL Gas (Enter Total of lines 10 thru 14)			
16				
17	TOTAL (Acct 281) (Total of 8, 15 and 16)			
18	Classification of TOTAL			
19	Federal Income Tax			
20	State Income Tax			
21	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES _ ACCELERATED AMORTIZATION PROPERTY (Account 281) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	(k)	
							1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
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							18
							19
							20
							21

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes rating to property not subject to accelerated amortization
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR	
			Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	4,343,192,939	1,051,806,661	440,658,517
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	4,343,192,939	1,051,806,661	440,658,517
6				
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	4,343,192,939	1,051,806,661	440,658,517
10	Classification of TOTAL			
11	Federal Income Tax	3,865,752,912	908,455,605	384,036,937
12	State Income Tax	477,440,027	143,351,056	56,621,580
13	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER PROPERTY (Account 282) (Continued)

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Debits		Credits		Balance at End of Year (k)	Line No.
		Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)		
							1
7,686,904	3,732,835		7,998,639	146	110,264	4,950,406,777	2
							3
							4
7,686,904	3,732,835		7,998,639		110,264	4,950,406,777	5
							6
							7
							8
7,686,904	3,732,835		7,998,639		110,264	4,950,406,777	9
							10
6,707,534	3,257,243		6,906,998		88,541	4,386,803,414	11
979,370	475,592		1,091,641		21,723	563,603,363	12
							13

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: h

182 - Regulatory Assets	$7,963,530
254 - North Carolina Excess Deferred Income Taxes	35,109
Total	$7,998,639

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

1. Report the information called for below concerning the respondent's accounting for deferred income taxes relating to amounts recorded in Account 283.
2. For other (Specify),include deferrals relating to other income and deductions.

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3		2,043,257,142	365,582,916	183,422,112
4				
5				
6				
7				
8				
9	TOTAL Electric (Total of lines 3 thru 8)	2,043,257,142	365,582,916	183,422,112
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18				
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	2,043,257,142	365,582,916	183,422,112
20	Classification of TOTAL			
21	Federal Income Tax	1,782,664,039	318,973,310	160,086,802
22	State Income Tax	260,593,103	46,609,606	23,335,310
23	Local Income Tax			

NOTES

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ACCUMULATED DEFERRED INCOME TAXES - OTHER (Account 283) (Continued)

3. Provide in the space below explanations for Page 276 and 277. Include amounts relating to insignificant items listed under Other.
4. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
		Debits		Credits			
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
29,476,661	12,328,556		2,454,545	146	569,440	2,240,680,946	3
							4
							5
							6
							7
							8
29,476,661	12,328,556		2,454,545		569,440	2,240,680,946	9
							10
							11
							12
							13
							14
							15
							16
							17
							18
29,476,661	12,328,556		2,454,545		569,440	2,240,680,946	19
							20
25,721,109	10,757,804		2,037,386		496,932	1,954,973,398	21
3,755,552	1,570,752		417,159		72,508	285,707,548	22
							23

NOTES (Continued)

FOOTNOTE DATA

Schedule Page: 276 Line No.: 3 Column: h

182 - Regulatory Assets	$2,425,977
254 - North Carolina Excess Deferred Income Taxes	28,568
Total	$2,454,545

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Regulatory Liability Related to Income Taxes	78,744,314	410/411/190/282	2,211,921	1,197,340	77,729,733
2	NCUC Docket No. E-7, Sub 1026					
3	PSCSC Docket No. 2013-59-E					
4						
5	NC State Excess Deferred Income Taxes - NC Retail	223,049,321	190/410/411	52,487,268	126,731	170,688,784
6	NCUC Docket No. E-7, Sub 1146					
7	Amortization from August 2018- July 2022					
8						
9	ARO Regulatory Liability	77,074,033			562,358,594	639,432,627
10	NCUC Docket No E-7 Sub 723					
11	PSCSC Docket No. 2003-84-E					
12						
13	I&D Regulatory Liability	33,538,626	228	3,336,869		30,201,757
14	NCUC Docket No E-7, Sub 1026					
15	PSCSC Docket 2013-59-E					
16						
17	NC REC Liability	69,359,165	456	6,520,601		62,838,564
18	NCUC Docket No. E-7, Sub 1052					
19	Amortization varies (typically 1 year)					
20						
21	SC Storm Reserve Fund					
22	PSCSC Docket No.2013-59-E	(12,347,270)			15,117,213	2,769,943
23						
24	OPEB Liability	37,762,728	228/926	2,605,512	3,519,573	38,676,789
25	FERC Docket No. AI07-1-000					
26						
27	Reg Liability-NQ - FAS 106 - Medical	61,650	926	5,272		56,378
28	FERC Docket No. AI07-1-000					
29						
30	NDTF Contaminated Liability	460,505,258				460,505,258
31	NCUC Docket No E-7 Sub 723					
32	PSCSC Docket No 2003-84-E					
33						
34	End of Life Reserves	94,953,097			14,795,433	109,748,530
35	NCUC Docket No. E-7, Sub 1026					
36						
37	Mark to Market Fuel - LT	542,849	142/174-6/182/232	542,849		
38						
39	TCJA Federal Excess Deferred Income Taxes - NC RI	1,666,438,970			1,030,275	1,667,469,245
40						
41	TOTAL	4,301,714,243		124,217,087	722,153,955	4,899,651,111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

OTHER REGULATORY LIABILITIES (Account 254)

1. Report below the particulars (details) called for concerning other regulatory liabilities, including rate order docket number, if applicable.
2. Minor items (5% of the Balance in Account 254 at end of period, or amounts less than $100,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	TCJA Federal Excess Deferred Income Taxes - Whole	225,952,570	410/411	11,580,912	140,389	214,512,047
2	Production Wholesale: Beginning January 2019 - gs					
3	Unprotected PPE : January 2019 - 20 years					
4	Unprotected Non-PPE : 5 years. Beginning January.					
5						
6	TCJA Federal Excess Deferred Income Taxes - Grosp	751,310,033	190	8,615,980	464,575	743,158,628
7						
8	TCJA Federal Excess Deferred Income Taxes - SC RI	573,865,830	410/411	16,701,984	354,352	557,518,198
9	PSCSC Docket No. 2018-319-E, Order No. 2019-323					
10						
11	NC State Excess Deferred Income Taxes - SC Retail		190/4101/411	10,150,375	87,020,789	76,870,414
12	PSCSC Docket No. 2018-319-E, Order No. 2019-323					
13	5 years beginning in June 2019					
14						
15	Interest Rate Swap Reg Liability	18,335,724	175	1,238,015		17,097,709
16						
17	Levelized NC State EDIT Rider - NC Retail	2,567,345	407	7,239,504	11,115,837	6,443,678
18	NCUC Docket No. E-7, Sub 1146					
19	4 years beginning August 2018					
20						
21	Job Retention Rider				20,502,740	20,502,740
22	NCUC Docket No. E-7, Subs 1146 & 1152					
23	Amortization from June 2020- May 2021					
24						
25	Rotable Fleet Spare		182/403	980,025	4,410,114	3,430,089
26	Docket No. E-7, Sub 986A					
27	Amortization ends January 2020					
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41	TOTAL	4,301,714,243		124,217,087	722,153,955	4,899,651,111

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATING REVENUES (Account 400)

1. The following instructions generally apply to the annual version of these pages. Do not report quarterly data in columns (c), (e), (f), and (g). Unbilled revenues and MWH related to unbilled revenues need not be reported separately as required in the annual version of these pages.
2. Report below operating revenues for each prescribed account, and manufactured gas revenues in total.
3. Report number of customers, columns (f) and (g), on the basis of meters, in addition to the number of flat rate accounts; except that where separate meter readings are added for billing purposes, one customer should be counted for each group of meters added. The -average number of customers means the average of twelve figures at the close of each month.
4. If increases or decreases from previous period (columns (c),(e), and (g)), are not derived from previously reported figures, explain any inconsistencies in a footnote.
5. Disclose amounts of $250,000 or greater in a footnote for accounts 451, 456, and 457.2.

Line No.	Title of Account (a)	Operating Revenues Year to Date Quarterly/Annual (b)	Operating Revenues Previous year (no Quarterly) (c)
1	Sales of Electricity		
2	(440) Residential Sales	3,051,598,700	3,045,387,976
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	2,372,750,932	2,303,046,264
5	Large (or Ind.) (See Instr. 4)	1,221,199,824	1,225,863,502
6	(444) Public Street and Highway Lighting	43,701,721	45,515,330
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales	79	
10	TOTAL Sales to Ultimate Consumers	6,689,251,256	6,619,813,072
11	(447) Sales for Resale	541,810,531	612,313,814
12	TOTAL Sales of Electricity	7,231,061,787	7,232,126,886
13	(Less) (449.1) Provision for Rate Refunds	25,560,067	184,514,676
14	TOTAL Revenues Net of Prov. for Refunds	7,205,501,720	7,047,612,210
15	Other Operating Revenues		
16	(450) Forfeited Discounts	19,713,241	20,000,193
17	(451) Miscellaneous Service Revenues	16,566,062	12,508,218
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	98,444,854	101,460,927
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	-45,896,162	-2,421,337
22	(456.1) Revenues from Transmission of Electricity of Others	99,206,132	94,204,325
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	188,034,127	225,752,326
27	TOTAL Electric Operating Revenues	7,393,535,847	7,273,364,536

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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ELECTRIC OPERATING REVENUES (Account 400)

6. Commercial and industrial Sales, Account 442, may be classified according to the basis of classification (Small or Commercial, and Large or Industrial) regularly used by the respondent if such basis of classification is not generally greater than 1000 Kw of demand. (See Account 442 of the Uniform System of Accounts. Explain basis of classification in a footnote.)
7. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
8. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
9. Include unmetered sales. Provide details of such Sales in a footnote.

MEGAWATT HOURS SOLD		AVG.NO. CUSTOMERS PER MONTH		Line No.
Year to Date Quarterly/Annual (d)	Amount Previous year (no Quarterly) (e)	Current Year (no Quarterly) (f)	Previous Year (no Quarterly) (g)	
				1
28,724,810	29,557,841	2,260,939	2,215,198	2
				3
29,576,666	29,547,014	362,174	357,880	4
21,271,896	21,623,383	6,123	6,176	5
320,907	305,007	21,581	17,193	6
				7
				8
				9
79,894,279	81,033,245	2,650,817	2,596,447	10
10,026,499	11,246,968	20	23	11
89,920,778	92,280,213	2,650,837	2,596,470	12
				13
89,920,778	92,280,213	2,650,837	2,596,470	14

Line 12, column (b) includes $ -3,713,757 of unbilled revenues.

Line 12, column (d) includes -214,759 MWH relating to unbilled revenues

FOOTNOTE DATA

Schedule Page: 300 Line No.: 17 Column: c

0451100- Misc Service Revenue	(12,509,098)
0451200- Generation Application Fee	881
	(12,508,217)

Schedule Page: 300 Line No.: 21 Column: c

Other Variable Revenues- Reg	(566,153)
Distribution Charge - Network	(3,534,759)
Metering - Network	(67,207)
Other Transmission Revenues	(1,915,987)
Comp For Serv Oth JointOwner	(17,988,996)
NC Unbilled Fuel Clause Rev	(1,059,538)
SC Unbilled Fuel Clause Rev	(1,339,787)
NC EE Deferred Revenue	40,020,094
SC EE Deferred Revenue	8,265,896
Other Electric Revenue	(5,374,341)
Gross Up Contr In Aid Of Const	(1,413,537)
Deferred Dsm Cost - NC	377,471
Other Revenue Affiliate	(12,890,259)
Profit Or Loss On Sale Of M&S	1,738
NC Unbilled Coal Inv Rev	(91,560)
Transmission Study Revenue	(1,738)
	2,421,337

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

REGIONAL TRANSMISSION SERVICE REVENUES (Account 457.1)

1. The respondent shall report below the revenue collected for each service (i.e., control area administration, market administration, etc.) performed pursuant to a Commission approved tariff. All amounts separately billed must be detailed below.

Line No.	Description of Service (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
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45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

1. Report below for each rate schedule in effect during the year the MWH of electricity sold, revenue, average number of customer, average Kwh per customer, and average revenue per Kwh, excluding date for Sales for Resale which is reported on Pages 310-311.
2. Provide a subheading and total for each prescribed operating revenue account in the sequence followed in "Electric Operating Revenues," Page 300-301. If the sales under any rate schedule are classified in more than one revenue account, List the rate schedule and sales data under each applicable revenue account subheading.
3. Where the same customers are served under more than one rate schedule in the same revenue account classification (such as a general residential schedule and an off peak water heating schedule), the entries in column (d) for the special schedule should denote the duplication in number of reported customers.
4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	RS - Residential Service	15,936,091	1,745,840,331	1,297,446	12,283	0.1096
2	RE - Res. Water Htr. & Space Cond	12,548,778	1,274,382,951	969,075	12,949	0.1016
3	RET - Res Water Htr & Space TOU					
4	RST - Residential Service TOU	5,045	536,096	228	22,127	0.1063
5	RB - Res. Service	75,808	9,158,892	5,641	13,439	0.1208
6	RT - Res. Service	53,944	4,794,341	234	230,530	0.0889
7	WC - Res. Service Controlled W-H	45,820	696,864	2,891	15,849	0.0152
8	ES - Energy Star	195,455	20,667,491	14,838	13,173	0.1057
9	OPERATING REVENUE		-93,552	-26,523		
10	Subtotal - Account 440	28,860,941	3,055,983,414	2,263,830	12,749	0.1059
11	Unbilled Alloc. - Residential	-136,131	-4,384,714			0.0322
12	Duplicate Customers			-2,891		
13	Total Residential	28,724,810	3,051,598,700	2,260,939	12,705	0.1062
14	G - General Service	3,678	60,638	85	43,271	0.0165
15	GA - General Service					
16	OPT - General Service	2,805,538	206,165,568	4,950	566,775	0.0735
17	OL - Outdoor Lighting	510,424	116,968,072	385,616	1,324	0.2292
18	BC - Bldg - Construction Service	20,440	3,598,641	10,830	1,887	0.1761
19	I - Industrial Service	2,854,945	224,820,456	4,706	606,661	0.0787
20	OPT - Industrial Service	6,954,112	384,605,147	490	14,192,065	0.0553
21	PG - Parallel Generation	3,123	762,860	7	446,143	0.2443
22	Industrial Service	1	3,497	1	1,000	3.4970
23	FL - Flood Lighting	32,612	4,473,369	9,335	3,494	0.1372
24	SG - (GEN) - Small General Ser					
25	SGS - Small General Service	5,846,144	672,370,622	319,394	18,304	0.1150
26	LGS - Large General Service	6,209,411	515,634,798	11,738	529,001	0.0830
27	S - UNMETERED STREET LIGHTS			4		
28	Yard Lighting					
29	OPTVG - General Service	13,328,743	810,304,860	16,321	816,662	0.0608
30	OPTVI - Industrial Service	9,612,137	526,933,866	1,098	8,754,223	0.0548
31	Water Heating					
32	HO-Hourly Pricing	2,573,495	117,482,475	34	75,691,029	0.0457
33	MP-Multiple Premises	171,629	9,924,333	23	7,462,130	0.0578
34	MFR-Miscellaneous Non-metered		74,366	108		
35	OPERATING REVENUE	1,500	729,975	-1,492	-1,005	0.4867
36	Subtotal - Account 442	50,927,932	3,594,913,543	763,248	66,725	0.0706
37	Duplicate Customers			-394,951		
38	Unbilled Alloc. - Commercial & In	-79,370	-962,787			0.0121
39	Total Commercial & Industrial	50,848,562	3,593,950,756	368,297	138,064	0.0707
40	PL - Street and Public Lighting	306,032	40,403,842	13,861	22,079	0.1320
41	TOTAL Billed	80,109,037	6,694,412,455	2,650,817	30,221	0.0836
42	Total Unbilled Rev.(See Instr. 6)	-214,758	-5,161,279	0	0	0.0240
43	TOTAL	79,894,279	6,689,251,176	2,650,817	30,139	0.0837

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SALES OF ELECTRICITY BY RATE SCHEDULES

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4. The average number of customers should be the number of bills rendered during the year divided by the number of billing periods during the year (12 if all billings are made monthly).
5. For any rate schedule having a fuel adjustment clause state in a footnote the estimated additional revenue billed pursuant thereto.
6. Report amount of unbilled revenue as of end of year for each applicable revenue account subheading.

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1	TS - Traffic Signal - Safety Non	12,433	2,476,883	7,488	1,660	0.1992
2	GL - Governmental Lighting Servic	1,455	513,395	224	6,496	0.3528
3	NL - Standard Lighting Service	244	121,378	8	30,500	0.4975
4	Subtotal - Account 444	320,164	43,515,498	21,581	14,835	0.1359
5	Unbilled Alloc. - Pub St & Highwa	743	186,222			0.2506
6	Total Public Street and Highway	320,907	43,701,720	21,581	14,870	0.1362
7	Total Retail Unbilled Fuel Clause					
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35						
36						
37						
38						
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40						
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42	Total Unbilled Rev.(See Instr. 6)	-214,758	-5,161,279	0	0	0.0240
43	TOTAL	79,894,279	6,689,251,176	2,650,817	30,139	0.0837

FOOTNOTE DATA

Schedule Page: 304 Line No.: 5 Column: a

Schedules no longer available for new customers.

Schedule Page: 304 Line No.: 28 Column: a

Schedules no longer available to new customers.

Schedule Page: 304.1 Line No.: 7 Column: a

All rate schedules are subject to fuel clause adjustment. For 2017 the total amount of unbilled fuel clause revenue is ($205,826,044). This includes North Carolina unbilled fuel clause revenue of ($101,268,223), North Carolina Experience Modification Factor (EMF) of ($46,568,922) including interest, and South Carolina unbilled fuel clause revenue of ($57,988,899).

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SALES FOR RESALE (Account 447)

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2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Blue Ridge Electric Membership					
2	Corporation	RQ	315	214	253	212
3	Blue Ridge Electric Membership					
4	Corporation	AD	315			
5	Central Electric Power Cooperative,Inc.	RQ	336	793	836	754
6	Central Electric Power Cooperative,Inc.	AD	336			
7	City of Concord	AD	327			
8	City of Kings Mountain	AD	331			
9	City of Greenwood, SC	AD	334			
10	Haywood Electric Membership Corporation	RQ	335	22	27	21
11	Haywood Electric Membership Corporation	AD	335			
12	Lockhart Power Company	RQ	332	42	50	38
13	Lockhart Power Company	AD	332			
14	North Carolina Electric Membership					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Corporation	RQ	326	60	60	60
2	North Carolina Electric Membership					
3	Corporation	AD	326			
4	North Carolina Municipal Power Agency 1	OS	318			
5	North Carolina Municipal Power Agency 1	AD	318			
6	Piedmont Electric Membership					
7	Corporation	RQ	316	80	89	82
8	Piedmont Electric Membership					
9	Corporation	AD	316			
10	Piedmont Municipal Power Agency	RQ	340	47		
11	Piedmont Municipal Power Agency	AD	340			
12	Rutherford Electric Membership					
13	Corporation	RQ	317	210	212	196
14	Rutherford Electric Membership					
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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SALES FOR RESALE (Account 447)

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Corporation	AD	317			
2	Town of Dallas	RQ	328	15	14	12
3	Town of Dallas	AD	328			
4	Town of Due West	RQ	329	2	3	2
5	Town of Due West	AD	329			
6	Town of Forest City	RQ	330	18	21	16
7	Town of Forest City	AD	330			
8	Town of Highlands	RQ	337	9	9	8
9	Town of Highlands	AD	337			
10	Town of Prosperity	RQ	333	2	2	2
11	Town of Prosperity	AD	333			
12	Western Carolina University	RQ	338	9	9	9
13	Western Carolina University	AD	338			
14	Broad River Energy, LLC	OS	4			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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	(a)	(b)	(c)	(d)	(e)	(f)
1	North Carolina Municipal Power Agency 1	OS	4			
2	Piedmont Municipal Power Agency	OS	4			
3	Southern Power Company - Rowan Plant	OS	4			
4	Southern Power Company -Cleveland Plant	OS	4			
5	North Carolina Electric Membership					
6	Corporation	OS	273			
7	Central Electric Power Cooperative,Inc.	OS	6	100		
8	Dominion Energy South Carolina, Inc.	OS	5			
9	Dominion Energy South Carolina, Inc.	OS	294			
10	Dominion Energy South Carolina, Inc.	AD	294			
11	Exelon Generation Company, LLC	OS	5			
12	Macquarie Energy, LLC	OS	5			
13	PJM Settlement, Inc.	OS	5			
14	PJM Settlement, Inc.	AD	5			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	South Carolina Public Service Authority	OS	293			
2	Southern Company Services, Inc.	OS	5			
3	The Energy Authority, Inc.	OS	5			
4	Westar Energy, Inc.	OS	5			
5	Brookfield Energy Marketing LP	OS	4			
6	City of Seneca, South Carolina	OS	4			
7	Eagle Energy Partners	OS	4			
8	Energy United Electric Membership					
9	Corporation	OS	4			
10	Exelon Generation Co., LLC	OS	4			
11	Endure Energy LLC	OS	4			
12	FPLEMT	OS	4			
13	Lockhart Power Company	OS	4			
14	Macquarie Energy	OS	4			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Mercuria Energy American	OS	4			
2	Morgan Stanley Capital Group Inc.	OS	4			
3	NTE	OS	4			
4	North Carolina Electric Membership					
5	Corporation	OS	4			
6	North Carolina Municipal Power Agency 1	OS	4			
7	Piedmont Municipal Power Agency	OS	4			
8	Rainbow Energy	OS	4			
9	South Carolina Electric & Gas Company	OS	4			
10	South Carolina Public Service Authority	OS	4			
11	Southern Power Company	OS	4			
12	The Energy Authority, Inc.	OS	4			
13	Westar Energy, Inc.	OS	4			
14	Duke Energy Progress, Inc.	LF	341			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:
RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projected load for this service in its system resource planning). In addition, the reliability of requirements service must be the same as, or second only to, the supplier's service to its own ultimate consumers.
LF - for tong-term service. "Long-term" means five years or Longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for Long-term firm service which meets the definition of RQ service. For all transactions identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or setter can unilaterally get out of the contract.
IF - for intermediate-term firm service. The same as LF service except that "intermediate-term" means longer than one year but Less than five years.
SF - for short-term firm service. Use this category for all firm services where the duration of each period of commitment for service is one year or less.
LU - for Long-term service from a designated generating unit. "Long-term" means five years or Longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of designated unit.
IU - for intermediate-term service from a designated generating unit. The same as LU service except that "intermediate-term" means Longer than one year but Less than five years.

Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	Duke Energy Progress, Inc.	AD	341			
2	Duke Energy Progress, Inc.	OS	10			
3						
4						
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
					1
1,411,625	44,783,289	30,854,711		75,638,000	2
					3
-26	-795,480	511,251		-284,229	4
3,979,226	135,355,995	84,137,252		219,493,247	5
-1,045	-2,607,352	1,282,629		-1,324,723	6
	2,150,276	348,195		2,498,471	7
	-62,653	54,396		-8,257	8
	-164,330	139,645		-24,685	9
131,759	4,485,802	2,784,554		7,270,356	10
-55	-102,934	44,860		-58,074	11
309,725	8,266,994	6,534,174		14,801,168	12
1,518	-381,033	314,525		-66,508	13
					14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
391,503	15,288,662	8,272,449		23,561,111	1
					2
	-398,075	142,156		-255,919	3
5,691	1,047,376	214,826		1,262,202	4
	2,974	683		3,657	5
					6
407,581	17,342,850	8,612,795		25,955,645	7
					8
	-305,973	148,437		-157,536	9
27,408	6,928,327	558,842	32,103	7,519,272	10
	293,467	39,629		333,096	11
					12
913,311	41,530,280	19,930,161		61,460,441	13
					14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
	-737,642	326,567		-411,075	1
73,975	2,347,158	1,614,542		3,961,700	2
	52,409	33,507		85,916	3
13,562	378,983	286,788		665,771	4
	9,779	5,843		15,622	5
113,434	4,395,227	2,466,273		6,861,500	6
	35,530	54,623		90,153	7
50,507	1,839,802	1,116,750		2,956,552	8
	-1,049	22,654		21,605	9
11,286	364,124	241,222		605,346	10
	-8,783	5,178		-3,605	11
45,540	1,776,112	962,488		2,738,600	12
	-22,095	20,410		-1,685	13
1,269			88,027	88,027	14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
3,197			4,202	4,202	1
2,106			21,290	21,290	2
9,223			408,595	408,595	3
8,407			195,683	195,683	4
					5
100,227		19,159,577		19,159,577	6
	4,580,000			4,580,000	7
505		27,191		27,191	8
4,765		176,125		176,125	9
		192		192	10
688		27,020		27,020	11
10,450		400,050		400,050	12
13,483		499,355		499,355	13
		1		1	14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,679		218,263		218,263	1
900		9,000		9,000	2
6,195		315,490		315,490	3
600		29,400		29,400	4
			-651	-651	5
			-501	-501	6
			-187	-187	7
					8
			-219	-219	9
			-1,240	-1,240	10
			-3	-3	11
			-45	-45	12
			-72	-72	13
837			-7,841	-7,841	14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
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9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
			-314	-314	1
			-1,828	-1,828	2
			300,271	300,271	3
					4
			-19,923	-19,923	5
			-29,620	-29,620	6
			-8,335	-8,335	7
			-109	-109	8
			-18	-18	9
			-913	-913	10
			-7,046	-7,046	11
			-334	-334	12
			-19	-19	13
1,964,628		59,872,307		59,872,307	14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
AD - for Out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.
4. Group requirements RQ sales together and report them starting at line number one. After listing all RQ sales, enter "Subtotal - RQ" in column (a). The remaining sales may then be listed in any order. Enter "Subtotal-Non-RQ" in column (a) after this Listing. Enter "Total" in column (a) as the Last Line of the schedule. Report subtotals and total for columns (9) through (k)
5. In Column (c), identify the FERC Rate Schedule or Tariff Number. On separate Lines, List all FERC rate schedules or tariffs under which service, as identified in column (b), is provided.
6. For requirements RQ sales and any type of-service involving demand charges imposed on a monthly (or Longer) basis, enter the average monthly billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP)
demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
7. Report in column (g) the megawatt hours shown on bills rendered to the purchaser.
8. Report demand charges in column (h), energy charges in column (i), and the total of any other types of charges, including out-of-period adjustments, in column (j). Explain in a footnote all components of the amount shown in column (j). Report in column (k) the total charge shown on bills rendered to the purchaser.
9. The data in column (g) through (k) must be subtotaled based on the RQ/Non-RQ grouping (see instruction 4), and then totaled on the Last -line of the schedule. The "Subtotal - RQ" amount in column (g) must be reported as Requirements Sales For Resale on Page 401, line 23. The "Subtotal - Non-RQ" amount in column (g) must be reported as Non-Requirements Sales For Resale on Page 401,iine 24.
10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
6,446		321,412	556	321,968	1
1,369		32,607		32,607	2
					3
					4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
7,880,442	285,083,605	168,373,001	32,103	453,488,709	
2,146,057	2,584,412	84,798,004	939,406	88,321,822	
10,026,499	**287,668,017**	**253,171,005**	**971,509**	**541,810,531**	

FOOTNOTE DATA

Schedule Page: 310.1 Line No.: 10 Column: j

Tagging adjustment was inadequately booked in 2019. A correction entry will be recorded in 2020.

Schedule Page: 310.2 Line No.: 14 Column: j

Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 1 Column: j

Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 2 Column: j

Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 3 Column: j

Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.3 Line No.: 4 Column: j

Represents Generation imbalance pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 5 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 6 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 7 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 9 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 10 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 11 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 12 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 13 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.4 Line No.: 14 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 1 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 2 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 3 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 5 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 6 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

FOOTNOTE DATA

Schedule Page: 310.5 Line No.: 7 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 8 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 9 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 10 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 11 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 12 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 13 Column: j

Represents credits for penalties collected for Generation imbalances pursuant to the Open Access Transmission Tariff.

Schedule Page: 310.5 Line No.: 14 Column: i

Represents intercompany sales pursuant to the Joint Dispatch Agreement between Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.

Schedule Page: 310.6 Line No.: 1 Column: i

Represents intercompany sales pursuant to the Joint Dispatch Agreement between Duke Energy Carolinas, LLC and Duke Energy Progress, Inc.

Schedule Page: 310.6 Line No.: 1 Column: j

Adjustment was related to 2016 BPM intercompany P2P invoice.

Schedule Page: 310.6 Line No.: 2 Column: i

Represents intercompany sales pursuant to the VACAR agreement.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	12,042,454	14,106,955
5	(501) Fuel	717,391,713	716,702,684
6	(502) Steam Expenses	55,034,789	53,517,190
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		65
9	(505) Electric Expenses	7,636,976	7,450,715
10	(506) Miscellaneous Steam Power Expenses	10,977,458	18,743,585
11	(507) Rents		
12	(509) Allowances	22,568,770	17,169,996
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	825,652,160	827,691,060
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	12,612,433	13,598,207
16	(511) Maintenance of Structures	22,739,350	25,391,613
17	(512) Maintenance of Boiler Plant	37,931,110	40,874,905
18	(513) Maintenance of Electric Plant	13,311,138	18,618,073
19	(514) Maintenance of Miscellaneous Steam Plant	5,203,508	5,957,186
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	91,797,539	104,439,984
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	917,449,699	932,131,044
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	36,793,768	36,573,149
25	(518) Fuel	270,718,518	276,244,035
26	(519) Coolants and Water	7,733,888	9,046,891
27	(520) Steam Expenses	40,805,819	45,423,250
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses	21,294,674	20,790,965
31	(524) Miscellaneous Nuclear Power Expenses	171,974,876	179,216,183
32	(525) Rents		618
33	TOTAL Operation (Enter Total of lines 24 thru 32)	549,321,543	567,295,091
34	Maintenance		
35	(528) Maintenance Supervision and Engineering	51,912,045	59,667,083
36	(529) Maintenance of Structures	10,739,931	13,388,034
37	(530) Maintenance of Reactor Plant Equipment	64,306,809	82,919,387
38	(531) Maintenance of Electric Plant	41,086,997	53,631,645
39	(532) Maintenance of Miscellaneous Nuclear Plant	47,275,835	55,488,912
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)	215,321,617	265,095,061
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)	764,643,160	832,390,152
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering	8,412,811	8,646,000
45	(536) Water for Power		
46	(537) Hydraulic Expenses	-896,783	-932,938
47	(538) Electric Expenses	5,400,529	5,612,382
48	(539) Miscellaneous Hydraulic Power Generation Expenses	9,037,136	8,678,588
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)	21,953,693	22,004,032
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering	2,460,454	2,733,907
54	(542) Maintenance of Structures	574,622	743,175
55	(543) Maintenance of Reservoirs, Dams, and Waterways	2,925,704	3,173,870
56	(544) Maintenance of Electric Plant	5,850,137	6,051,617
57	(545) Maintenance of Miscellaneous Hydraulic Plant	3,889,957	4,021,019
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)	15,700,874	16,723,588
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)	37,654,567	38,727,620

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	8,110,047	8,734,129
63	(547) Fuel	407,433,333	507,677,739
64	(548) Generation Expenses	2,110,166	2,176,467
65	(549) Miscellaneous Other Power Generation Expenses	9,310,065	9,922,370
66	(550) Rents	-131,834	-61,682
67	TOTAL Operation (Enter Total of lines 62 thru 66)	426,831,777	528,449,023
68	Maintenance		
69	(551) Maintenance Supervision and Engineering	4,825,688	5,050,700
70	(552) Maintenance of Structures	6,704,865	6,882,389
71	(553) Maintenance of Generating and Electric Plant	19,389,319	6,775,578
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	5,027,925	4,472,389
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	35,947,797	23,181,056
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	462,779,574	551,630,079
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	428,148,296	501,354,859
77	(556) System Control and Load Dispatching		32,042
78	(557) Other Expenses	125,885,291	-17,901,355
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	554,033,587	483,485,546
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	2,736,560,587	2,838,364,441
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	25,295	12,057
84			
85	(561.1) Load Dispatch-Reliability	1,538,723	1,569,257
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	8,696,538	8,618,014
87	(561.3) Load Dispatch-Transmission Service and Scheduling	689,034	812,692
88	(561.4) Scheduling, System Control and Dispatch Services		832
89	(561.5) Reliability, Planning and Standards Development	417,466	305,750
90	(561.6) Transmission Service Studies	81,077	9,768
91	(561.7) Generation Interconnection Studies	10,820	-1,511
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,080,238	1,647,297
94	(563) Overhead Lines Expenses	1,112,296	938,130
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	3,292,861	3,035,624
97	(566) Miscellaneous Transmission Expenses	10,203,769	11,314,151
98	(567) Rents	75,379	147,140
99	TOTAL Operation (Enter Total of lines 83 thru 98)	28,223,496	28,409,201
100	Maintenance		
101	(568) Maintenance Supervision and Engineering		
102	(569) Maintenance of Structures	134,985	943,999
103	(569.1) Maintenance of Computer Hardware	2,179	77,034
104	(569.2) Maintenance of Computer Software	3,281,142	2,667,421
105	(569.3) Maintenance of Communication Equipment		210
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	8,446,130	8,453,316
108	(571) Maintenance of Overhead Lines	18,603,670	25,081,168
109	(572) Maintenance of Underground Lines	-31,623	-1,248
110	(573) Maintenance of Miscellaneous Transmission Plant	55,862	1,451,315
111	TOTAL Maintenance (Total of lines 101 thru 110)	30,492,345	38,673,215
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	58,715,841	67,082,416

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services		
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)		
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)		
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,338,227	1,207,429
135	(581) Load Dispatching	7,094,511	8,425,724
136	(582) Station Expenses	1,461,840	1,282,105
137	(583) Overhead Line Expenses	1,904,855	2,980,905
138	(584) Underground Line Expenses	11,098,864	11,475,994
139	(585) Street Lighting and Signal System Expenses	58,694	492,035
140	(586) Meter Expenses	9,779,908	10,709,054
141	(587) Customer Installations Expenses	9,991,964	10,526,414
142	(588) Miscellaneous Expenses	51,769,561	45,615,305
143	(589) Rents	114,638	117,896
144	TOTAL Operation (Enter Total of lines 134 thru 143)	94,613,062	92,832,861
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	2,179,061	977,779
147	(591) Maintenance of Structures		2,056
148	(592) Maintenance of Station Equipment	3,859,167	4,569,308
149	(593) Maintenance of Overhead Lines	139,651,191	195,064,035
150	(594) Maintenance of Underground Lines	16,365,021	20,327,339
151	(595) Maintenance of Line Transformers	2,424,286	2,816,316
152	(596) Maintenance of Street Lighting and Signal Systems	13,160,168	12,799,453
153	(597) Maintenance of Meters	1,861,936	2,314,975
154	(598) Maintenance of Miscellaneous Distribution Plant	2,806,822	3,921,976
155	TOTAL Maintenance (Total of lines 146 thru 154)	182,307,652	242,793,237
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	276,920,714	335,626,098
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	219,727	92,741
160	(902) Meter Reading Expenses	1,958,980	2,455,088
161	(903) Customer Records and Collection Expenses	65,530,595	67,078,376
162	(904) Uncollectible Accounts	17,571,721	16,637,687
163	(905) Miscellaneous Customer Accounts Expenses	255,858	264,709
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	85,536,881	86,528,601

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision		
168	(908) Customer Assistance Expenses	988	4,205
169	(909) Informational and Instructional Expenses	209,296	149,499
170	(910) Miscellaneous Customer Service and Informational Expenses	17,994,267	19,151,412
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	18,204,551	19,305,116
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision	93	4,784
175	(912) Demonstrating and Selling Expenses	14,454,736	13,610,071
176	(913) Advertising Expenses	348,469	565,426
177	(916) Miscellaneous Sales Expenses	271,925	58,889
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	15,075,223	14,239,170
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	163,016,263	241,315,539
182	(921) Office Supplies and Expenses	87,257,388	86,395,771
183	(Less) (922) Administrative Expenses Transferred-Credit	29,020,292	39,763,864
184	(923) Outside Services Employed	62,952,695	71,238,493
185	(924) Property Insurance	-10,173,361	2,399,590
186	(925) Injuries and Damages	17,774,841	21,835,563
187	(926) Employee Pensions and Benefits	88,007,473	102,239,981
188	(927) Franchise Requirements		47
189	(928) Regulatory Commission Expenses	15,498,675	12,121,234
190	(929) (Less) Duplicate Charges-Cr.	37,455,111	34,592,827
191	(930.1) General Advertising Expenses	3,530,931	5,346,453
192	(930.2) Miscellaneous General Expenses	-25,764,325	-26,059,961
193	(931) Rents	49,672,355	45,607,149
194	TOTAL Operation (Enter Total of lines 181 thru 193)	385,297,532	488,083,168
195	Maintenance		
196	(935) Maintenance of General Plant	529,560	2,861,306
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	385,827,092	490,944,474
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	3,576,840,889	3,852,090,316

FOOTNOTE DATA

Schedule Page: 320 Line No.: 5 Column: b

Total fuel costs include accounts 0501007, 0501008 and 0501009 for Coal Ash BeneficialReuse in the amount of $7,929,494.

Schedule Page: 320 Line No.: 5 Column: c

Total fuel costs include accounts 0501007, 0501008 and 0501009 for Coal Ash Beneficial Reuse in the amount of $52,522,476.

Schedule Page: 320 Line No.: 13 Column: b

This includes $22,565,346 for renewable energy credits consumption expense represented in account 0509213. This includes $422,392 of expenses related to Hydro plants sold in 2019. This also includes $3,424 of Emission Allowances in account 0509000 as reported on page 228a.

Schedule Page: 320 Line No.: 13 Column: c

This includes $17,165,794 for renewable energy credits consumption expense represented in account 0509213. It also includes $4,202 of Emission Allowances in account 0509000 as reported on page 228a.

Schedule Page: 320 Line No.: 20 Column: b

This includes $314,923 of expenses related to Hydro plants sold in 2019.

Schedule Page: 320 Line No.: 63 Column: b

Total fuel costs include Biogas accounts 0547106 and 0547107 in the amount of $959,784

Schedule Page: 320 Line No.: 63 Column: c

Total fuel costs include Biogas accounts 0547106 and 0547107 in the amount of $1,665,650.

Schedule Page: 320 Line No.: 134 Column: b

includes accounts '0870000,0880000.

Schedule Page: 320 Line No.: 196 Column: b

Total Maintenance of General Plant include accounts 0932000, 0935100 and 0935200.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	231 DIXON 74 SOLAR I LLC	LU	(1)			
2	232 LONG BRANCH 29 SOLAR I LLC	LU	(1)			
3	232 LONG BRANCH 29 SOLAR I LLC	AD	(1)			
4	ABT INC	LU	(1)			
5	ACTIVE CONCEPTS LLC	LU	(1)			
6	AKS REAL ESTATE HOLDINGS LLC	LU	(1)			
7	ALAMANCE HYDRO LLC	LU	(1)			
8	AMETHYST SOLAR LLC	LU	(1)			
9	ANGEL SOLAR LLC	LU	(1)			
10	APPLE DATA CENTER PV2	IU	(1)			
11	APPLE FUEL CELL FACILITY	LU	(1)			
12						
13	APPLE INC CLAREMONT PV3	LU	(1)			
14	APPLE ONE LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	APPLE PV1	LU	(1)			
2	Aquenergy - Piedmont Hydro	LU	(1)			
3	Aquenergy - Ware Shoals Hydro	LU	(1)			
4	ARARAT ROCK SOLAR LLC	LU	(1)			
5	ARNDT FARM LLC	LU	(1)			
6	ASHLEY SOLAR	LU	(1)			
7	ATOOD SOLAR II LLC	LU	(1)			
8	AUDREY SOLAR LLC	LU	(1)			
9	AUTEN ROAD FARM LLC	LU	(1)			
10	AVALON HYDROPOWER LLC	LU	(1)			
11	AYRSHIRE HOLDINGS LLC	LU	(1)			
12	BAKATSIAS SOLAR FARM LLC	LU	(1)			
13	BANK OF AMERICA	LU	(1)			
14	BARRY R WHARTON	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BATTLEGROUND SOLAR I LLC	LU	(1)			
2	BEACON SOLAR ONE LLC	LU	(1)			
3	BEETLE SOLAR LLC	LU	(1)			
4	BELWOOD FARM LLC	LU	(1)			
5	BERNHARDT FURNITURE COMPANY	LU	(1)			
6	BETH SOLAR LLC	LU	(1)			
7	BG STEWART SOLAR FARM LLC	LU	(1)			
8	BIG BOY SOLAR LLC	LU	(1)			
9	BIOMERIEUX INC	LU	(1)			
10	BLACKSBURG ENVIRONMENTAL	IU	(1)			
11	AND ENERGY LLC					
12	BLUE BRIGHT VENTURES LLC	LU	(1)			
13	BOYD LEON HYDER	LU	(1)			
14	BRANCH JAMES DAVID DR	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	BRIAN M ATTIS	LU	(1)			
2	BRYAN C TURNER	LU	(1)			
3	BUDDY SOLAR LLC	LU	(1)			
4	BURLINGTON HYDRO LLC	LU	(1)			
5	C2 Solar	IU	(1)			
6	CAROL JEAN SOLAR LLC	LU	(1)			
7	CARRBORO COMMUNITY SOLAR LLC	LU	(1)			
8	Catawba County - Blackburn Landfill	LU	(1)			
9	CATAWBA GREEN STEP SOLAR LLC	LU	(1)			
10	CATAWBA SOLAR LLC	LU	(1)			
11	CHAPEL HILL TIRE CO	LU	(1)			
12	CHAPEL HILL TIRE COMPANY INC.	LU	(1)			
13	CHARLIE SOLAR LLC	LU	(1)			
14	CHARLOTTE SOLAR LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	CHEROKEE FALLS HYDRO	LU	(1)			
2	CISCO SYSTEMS INC	IU	(1)			
3	CITY OF CHARLOTTE	IU	(1)			
4	CLEAN ENERGY LLC	LU	(1)			
5	Cliffside Mills LLC	LU	(1)			
6	CLINE SOLAR LLC	LU	(1)			
7	CLOVER SCHOOL DISTRICT 2	LU	(1)			
8	COC SURRY LFG LLC	LU	(1)			
9	COMMONWEALTH BRANDS INC	LU	(1)			
10	CONCORD ENERGY LLC	LU	(1)			
11	CONGOLINA SOLAR LLC	LU	(1)			
12	Converse Energy - Clifton Dam #3 Hydro	LU	(1)			
13	COUNTY HOME SOLAR CENTER LLC	LU	(1)			
14	CT WILSON PROPERTIES LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Cube Yadkin Generation LLC	IU	(1)			
2	DANIEL FARM LLC	LU	(1)			
3	DANIELLE SEAMAN	LU	(1)			
4	DAVID H NEWMAN	LU	(1)			
5	DAVIDSON GAS PRODUCERS LLC	LU	(1)			
6	DDM MORTGAGE CORPORATION	LU	(1)			
7	DEE INDUSTRIES	LU	(1)			
8	DELTA PRODUCTS CORP.	LU	(1)			
9	DIANE E JAMES	LU	(1)			
10	DIBRELL FARM LLC	LU	(1)			
11	DIRK J SPRUYT	LU	(1)			
12	DIXON DAIRY ROAD LLC	LU	(1)			
13	DON A BICKNELL	LU	(1)			
14	DRAGSTRIP FARM	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	DURHAM LANDFILL ELECTRICITY LLC	LU	(1)			
2	DURHAM SOLAR LLC	LU	(1)			
3	EARNHART-CHILDRESS RACING	LU	(1)			
4	TECHNOLOGIES LLC					
5	ELLIANA SOLAR LLC	LU	(1)			
6	ELSEWHERE LIVING MUSEUM	LU	(1)			
7	ESTES EXPRESS LINES INC	LU	(1)			
8	FACILE SOLAR LLC	LU	(1)			
9	FISHER SOLAR FARM LLC	LU	(1)			
10	FLASH SOLAR LLC	LU	(1)			
11	FLS OWNER II LLC	LU	(1)			
12	FOOTHILLS WINEWORX INC	LU	(1)			
13	FREEMONT SOLAR CENTER LLC	LU	(1)			
14	Freightliner Corp	IU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	FREIRICH FOODS LLC	LU	(1)			
2	FRESH AIR ENERGY XV LLC	LU	(1)			
3	FRESH AIR ENERGY XX LLC	LU	(1)			
4	FRESH AIR ENERGY XXIX LLC	LU	(1)			
5	GAS RECOVERY SYSTEMS LLC	LU	(1)			
6	GASTON COUNTY	LU	(1)			
7	GASTONIA SOLAR CENTER LLC	LU	(1)			
8	GENERAL ELECTRIC COMPANY	LU	(1)			
9	GERALD W. MEISNER	LU	(1)			
10	GERMANTOWN SOLAR LLC	LU	(1)			
11	GO STORE IT ROPER LLC	IU	(1)			
12	GO STORE IT ROPER LLC	AD	(1)			
13	GOOD SOLAR ELECTRIC LLC	IU	(1)			
14	GREENSBORO PLUMBING SUPPLY CO	LU	(1)			
	Total					

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1	GREENVILLE COUNTY SCHOOLS	LU	(1)			
2	GREENVILLE GAS PRODUCERS LLC	LU	(1)			
3	Haneline Power LLC	LU	(1)			
4	HAROLD FERGUSON	LU	(1)			
5	Haw River Hydro Co - Saxapahaw Hydro	LU	(1)			
6	HAYNES FARM LLC	LU	(1)			
7	HMS Holdings Limited Partnership	LU	(1)			
8	HOFFMAN & HOFFMAN	LU	(1)			
9	HOWELL MIDLAND FARM LLC	LU	(1)			
10	HUSKY SOLAR LLC	LU	(1)			
11	HUTCHINSON FARM LLC	LU	(1)			
12	INDUSTRIAL CENTERS LLC	LU	(1)			
13	INNOVATIVE SOLAR 14 LLC	LU	(1)			
14	INNOVATIVE SOLAR 15 LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	INNOVATIVE SOLAR 16 LLC	LU	(1)			
2	INNOVATIVE SOLAR 18 LLC	LU	(1)			
3	INNOVATIVE SOLAR 23 LLC	LU	(1)			
4	INNOVATIVE SOLAR 26 LLC	LU	(1)			
5	IRVINE RIVER COMPANY	LU	(1)			
6	ITRON INC	LU	(1)			
7	JACOB SOLAR LLC	LU	(1)			
8	Jafasa Farms Greenhouse	LU	(1)			
9	Jafasa Farms Residence	LU	(1)			
10	JAMES J BOYLE	LU	(1)			
11	JARROD W BARTRON	LU	(1)			
12	JEFFERY LYNN PARDUE	LU	(1)			
13	JIM AND LINDA ALEXANDER	LU	(1)			
14	JOHN H. DILIBERTI	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	JUBA ALUMINUM PRODUCTS COMPANY	LU	(1)			
2	JUDITH LOBERG	LU	(1)			
3	KMBA LLC	LU	(1)			
4	LAFAYETTE SOLAR I LLC	LU	(1)			
5	LAMAR BAILES	LU	(1)			
6	LAURA J BALLANCE	LU	(1)			
7	LAWRENCE ELECTRIC	LU	(1)			
8	LEON'S BEAUTY SCHOOL INC	LU	(1)			
9	LINCOLN SOLAR LLC	LU	(1)			
10	LOCKHART - LOWER PACOLET HYDRO	LU	(1)			
11	LOCKHART - UPPER PACOLET HYDRO	LU	(1)			
12	LOCKHART BIOENERGY LLC	LU	(1)			
13	LOCKHART Minimum Flow	LU	(1)			
14	LOCKHART POWER COMPANY	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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1	LOTUS SOLAR LLC	LU	(1)			
2	LUX SOLAR I LLC	LU	(1)			
3	LYNWOOD SOLAR I LLC	LU	(1)			
4	MARIPOSA SOLAR CENTER LLC	LU	(1)			
5	MARK S TRUSTIN	LU	(1)			
6	MARKET FARM LLC	LU	(1)			
7	MARSHVILLE FARM LLC	LU	(1)			
8	MARTIN TRUEX JR. LLC	LU	(1)			
9	MAYBERRY SOLAR LLC	LU	(1)			
10	Mayo Hydropower LLC - Mayo Hydro	LU	(1)			
11	MCBRIDE PLACE ENERGY LLC	LU	(1)			
12	MCBRIDE PLACE ENERGY LLC	AD	(1)			
13	MEADOWBROOK SOLAR LLC	LU	(1)			
14	MIDTOWN SHOPS LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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1	Mill Shoals Hydro - High Shoals Hydro	LU	(1)			
2	MILL SOLAR I LLC	LU	(1)			
3	MILLIKAN FARM LLC	LU	(1)			
4	MILO SOLAR LLC	LU	(1)			
5	MINNESOTA MINING & MFG CO	IU	(1)			
6	MINNIE SOLAR LLC	LU	(1)			
7	MISENHEIMER FARM LLC	LU	(1)			
8	MOCKSVILLE FARM LLC	LU	(1)			
9	MONROE MOORE FARM LLC	LU	(1)			
10	MOORE SOLAR #2 LLC	LU	(1)			
11	MOORE SOLAR FARM LLC	LU	(1)			
12	NARENCO	LU	(1)			
13	NC SOLAR DOCKS LLC	LU	(1)			
14	NEISLER STREET SOLAR I LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	NEWTON-CONOVER CITY SCHOOLS	LU	(1)			
2	NICK SOLAR LLC	LU	(1)			
3	Northbrook Carolina - Boyds Mill Hydro	IU	(1)			
4	Northbrook Carolina - Holliday's	IU	(1)			
5	Bridge Hydro		(1)			
6	Northbrook Carolina - Saluda Hydro	IU	(1)			
7	Northbrook Carolina-TurnerShoalsHydro	IU	(1)			
8	NORTHBROOK CAROLINA (Bryson)	LU	(1)			
9	NORTHBROOK CAROLINA (Franklin)	LU	(1)			
10	NORTHBROOK CAROLINA (Gaston Shoals)	LU	(1)			
11	NORTHBROOK HYDRO II (Mission Dam)	LU	(1)			
12	NORTHBROOK TUXEDO	LU	(1)			
13	NYPRO INC	LU	(1)			
14	OAKDALE HOLDING LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	OENOPHILIA	LU	(1)			
2	OLD CAROLEEN SOLAR FARM LLC	LU	(1)			
3	OLD DOMINION FREIGHT LINE INC	LU	(1)			
4	OLD PAGELAND-MONROE ROAD	LU	(1)			
5	SOLAR FARM LLC		(1)			
6	ORBIT ENERGY CHARLOTTE LLC	LU	(1)			
7	ORGAN CHURCH SOLAR LLC	LU	(1)			
8	OWEN SOLAR LLC	LU	(1)			
9	PAUL M NEUBAUER	LU	(1)			
10	Pelzer Hydro Co - Lower Pelzer Hydro	LU	(1)			
11	Pelzer Hydro Co - Upper Pelzer Hydro	LU	(1)			
12	PELZER SOLAR I LLC	LU	(1)			
13	Pickins Mill Hydro LLC	IU	(1)			
14	PIEDMONT COMPANY INC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	PIERRE BURKE	LU	(1)			
2	PUBLIC LIBRARY OF CHARLOTTE	LU	(1)			
3	R B SOLAR LLC	LU	(1)			
4	R LAWRENCE ASHE JR	LU	(1)			
5	RAJAH Y CHACKO	LU	(1)			
6	RAJENDRA MOREY	LU	(1)			
7	RAYLEN VINEYARDS INC	LU	(1)			
8	REBECCA G LASKODY	LU	(1)			
9	REDMON SOLAR FARM LLC	LU	(1)			
10	REI 2 LLC	LU	(1)			
11	ROBERT SKIRBOLL	LU	(1)			
12	ROCKWELL SOLAR LLC	LU	(1)			
13	RONNIE B POWERS	LU	(1)			
14	ROPER FARM LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	ROUSCH & YATES RACING ENGINES LLC	LU	(1)			
2	RUSSELL VON STEIN	LU	(1)			
3	RUTHERFORD FARM LLC	LU	(1)			
4	SAIA MOTOR FREIGHT LINE LLC	LU	(1)			
5	SALEM ENERGY SYSTEMS LLC	LU	(1)			
6	SALISBURY SOLAR LLC	LU	(1)			
7	SANDAN FARM	LU	(1)			
8	SHELBY RANDOLPH ROAD SOLAR I LLC	LU	(1)			
9	SHOE SHOW INC	LU	(1)			
10	SID SOLAR I LLC	LU	(1)			
11	SIGMON CATAWBA FARM LLC	LU	(1)			
12	SONNE TWO LLC	LU	(1)			
13	SOPHIE SOLAR LLC	LU	(1)			
14	SOUTH WINSTON FARM LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

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OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	South Yadkin Power Inc.	LU	(1)			
2	SOUTHDATA INC	LU	(1)			
3	SPARTANBURG WATER SYSTEM	LU	(1)			
4	SPENCER FARM LLC	LU	(1)			
5	SPENCER MOUNTAIN HYDROPOWER LLC	LU	(1)			
6	STANLEY CHAMBERLAIN	LU	(1)			
7	Star Solar LLC	LU	(1)			
8	STATESVILLE SOLAR LLC	LU	(1)			
9	Steve Mason Ent. Inc. - Long Shoals H	LU	(1)			
10	STIKELEATHER FARM LLC	LU	(1)			
11	STONEVILLE SOLAR LLC	LU	(1)			
12	STOUT FARM LLC	LU	(1)			
13	SUN CAPITAL INC	LU	(1)			
14	SUN EDISON LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	T.S. DESIGNS INC.	LU	(1)			
2	TEMPLE EMANUEL	LU	(1)			
3	TENCARVA MACHINERY COMPANY	LU	(1)			
4	TerraForm LLC; DBA: SunE B9 Holdings	LU	(1)			
5	LLC					
6	THE CITY OF CHARLOTTE	LU	(1)			
7	THE MEASURED DOSE PHARMACY INC.	LU	(1)			
8	THE NORTHWESTERN MUTUAL LIFE	LU	(1)			
9	INSURANCE					
10	THE ROCKET SHOP LLC	LU	(1)			
11	THOMAS SCHOPLER	LU	(1)			
12	TIBURON HOLDINGS LLC	LU	(1)			
13	TONY M SMITH	LU	(1)			
14	Town Of Lake Lure - Lake Lure Hydro	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	TRIPPLE STATE FARM LLC	LU	(1)			
2	TROPICAL NUT & FRUIT CO	LU	(1)			
3	TWC ADMINISTRATION LLC	LU	(1)			
4	TWO LINES FARM LLC	LU	(1)			
5	UNIFI MANUFACTURING INC	LU	(1)			
6	UNITED SEWING MACHINE SALES LLC	LU	(1)			
7	UNITED THERAPEUTICS CORPORATION	LU	(1)			
8	VETRORESINA LLC	LU	(1)			
9	VIDYA SAGAR SETHI	LU	(1)			
10	VIOLET SOLAR LLC	LU	(1)			
11	VOLT SOLAR LLC	LU	(1)			
12	W B MOORE CO OF CHAR	LU	(1)			
13	WACO FARM LLC	LU	(1)			
14	WALLACE & GRAHAM PA	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	WALTER C. MCGERVEY	LU	(1)			
2	WALTER O BRADLEY	LU	(1)			
3	WATAUGA COUNTY	LU	(1)			
4	WEST SALISBURY FARM LLC	LU	(1)			
5	WHITE CROSS FARM LLC	LU	(1)			
6	WHITE CROSS SOLAR LLC	LU	(1)			
7	WHITE STREET RENEWABLES LLC	LU	(1)			
8	WHITT SOLAR LLC	LU	(1)			
9	WILKES COUNTY	LU	(1)			
10	WILLIAM D MOORE	LU	(1)			
11	WILLIAM P MILLER	LU	(1)			
12	WM RENEWABLE ENERGY LLC	LU	(1)			
13	WRIGHT OF THOMASVILLE INC	LU	(1)			
14	YADKIN 601 FARM LLC	LU	(1)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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1	YADKINVILLE SOLAR LLC	LU	(1)			
2	YORK ROAD SOLAR I LLC	LU	(1)			
3	YUZE HOLDINGS LLC	IU	(1)			
4						
5						
6	Residential Solar Credit	LU				
7	Southeastern Power Administration	OS	124			
8	Small Customer Generator Credits	OS				
9						
10	North Carolina Municipal Power Agency	EX	271			
11	North Carolina Electric Member	EX	273			
12	Corporation					
13	Piedmont Municipal Power Agency	EX	314			
14	North Carolina Electric Member	EX	273			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
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1	Corporation					
2	North Carolina Municipal Power Agency	OS	271			
3	North Carolina Electric Member	OS	273			
4	Corporation					
5	Piedmont Municipal Power Agency	OS	313			
6						
7	Blue Ridge Electric Membership	RQ	315			
8	Corporation					
9	Blue Ridge Electric Membership	AD	315			
10	Corporation					
11	Carolina Power & Light Company	OS	45			
12	Cherokee County Cogeneration Partners	OS	(2)			
13	LLC					
14	Cherokee County Cogeneration Partners	AD	(2)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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1	LLC	0				
2	City of Concord North Carolina	AD	327			
3						
4	DE Progress	OS	345			
5	DE Progress	OS	341			
6	DE Progress	AD	341			
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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1	Dominion Energy South Carolinas	OS	(2)			
2	Inc (SCE&G)	0				
3	EDF Trading North America LLC	OS	(2)			
4	Exelon Generation Company LLC	OS	(2)			
5	Haywood Electric Membership	RQ	335			
6	Corporation	0				
7	Haywood Electric Membership	AD	335			
8	Corporation	0				
9						
10						
11	Macquarie Energy LLC	OS	(2)			
12	Morgan Stanley Capital Group inc	OS	(2)			
13						
14	NC Electric Member Corporation	OS	(2)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	NC Electric Member Corporation	RQ	326			
2	North Carolina Municipal Power Agency	OS	(2)			
3	Number 1					
4	North Carolina Municipal Power Agency	RQ	318			
5	Number 1					
6	NTE Carolinas LLC	OS	(2)			
7	Piedmont Electric Membership	RQ	316			
8	Corporation					
9	Piedmont Electric Membership	AD	316			
10	Corporation					
11	Piedmont Municipal Power Agency	OS	340			
12	PJM Settlements Inc	OS	(2)			
13	PJM Settlements Inc	AD	(2)			
14	South Carolina Electric & Gas Company	OS	(2)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Transmission					
2	Southern Company Services Inc.	OS	(2)			
3	Tennessee Valley Authority	OS	(2)			
4	The Energy Authority	OS	(2)			
5						
6	Town of Dallas North Carolina	RQ	328			
7	Town of Forest City North Carolina	RQ	330			
8						
9	Broad River Energy Center c/o Calpine	EX	(3)			
10	Corp					
11	Macquarie Energy LLC	EX	(3)			
12	NCMPA	EX	(3)			
13	NTE	EX	(3)			
14	Piedmont Municipal Power Agency	EX	(3)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

RQ - for requirements service. Requirements service is service which the supplier plans to provide on an ongoing basis (i.e., the supplier includes projects load for this service in its system resource planning). In addition, the reliability of requirement service must be the same as, or second only to, the supplier's service to its own ultimate consumers.

LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

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LU - for long-term service from a designated generating unit. "Long-term" means five years or longer. The availability and reliability of service, aside from transmission constraints, must match the availability and reliability of the designated unit.

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern Power Company - Cleveland	EX	(3)			
2	Plant					
3	Southern Power Company - Rowan Plant	EX	(3)			
4						
5	City of Concord	EX	(4)			
6	City of Kings Mountain	EX	(4)			
7	City of Seneca	EX	(4)			
8	EnergyUnited Electric Memb	EX	(4)			
9	Greenwood Comm of Pblc Works	EX	(4)			
10	NC Electric Membership Corp	EX	(4)			
11	NCMPA	EX	(4)			
12	Piedmont Municipal Power Agenc	EX	(4)			
13	SCE&G COMPANY	EX	(4)			
14	South Carolina Public Service	EX	(4)			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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LF - for long-term firm service. "Long-term" means five years or longer and "firm" means that service cannot be interrupted for economic reasons and is intended to remain reliable even under adverse conditions (e.g., the supplier must attempt to buy emergency energy from third parties to maintain deliveries of LF service). This category should not be used for long-term firm service firm service which meets the definition of RQ service. For all transaction identified as LF, provide in a footnote the termination date of the contract defined as the earliest date that either buyer or seller can unilaterally get out of the contract.

IF - for intermediate-term firm service. The same as LF service expect that "intermediate-term" means longer than one year but less than five years.

SF - for short-term service. Use this category for all firm services, where the duration of each period of commitment for service is one year or less.

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IU - for intermediate-term service from a designated generating unit. The same as LU service expect that "intermediate-term" means longer than one year but less than five years.

EX - For exchanges of electricity. Use this category for transactions involving a balancing of debits and credits for energy, capacity, etc. and any settlements for imbalanced exchanges.

OS - for other service. Use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote for each adjustment.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Authority - P2P					
2	Brookfield Energy Marketing LP	OS	890			
3	Brookfield Renewable	OS	890			
4	Eagle Energy Partners	OS	890			
5	Endure Energy LLC	OS	890			
6	Exelon Power Team	OS	890			
7	Florida Power & Light EMT	OS	890			
8	NTE	OS	890			
9	Lockhart Power Company	OS	890			
10	Macquarie Energy LLC	OS	890			
11	Mercuria Energy American	OS	890			
12	Morgan Stanley Capital Grp INC	OS	890			
13	Rainbow Energy Marketing	OS	890			
14	SC Public Service Authority	OS	890			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER (Account 555)
(Including power exchanges)

1. Report all power purchases made during the year. Also report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges.
2. Enter the name of the seller or other party in an exchange transaction in column (a). Do not abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the seller.
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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	Southern Wholesale	OS	890			
2	Tenaska Power Services Co.	OS	890			
3	The Energy Authority	OS	890			
4	Westar Energy	OS	890			
5						
6	Operating Regulating	EX	(5)			
7						
8						
9						
10						
11						
12						
13						
14						
	Total					

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
3,981				266,890		266,890	1
2,507				168,256		168,256	2
774				57,082		57,082	3
315				20,986		20,986	4
95				3,042		3,042	5
2				51		51	6
342				20,559		20,559	7
5,848				393,247		393,247	8
9,131				616,248		616,248	9
39,345				2,346,929		2,346,929	10
59,515				3,408,102		3,408,102	11
							12
35,724				2,126,497		2,126,497	13
9,612				647,217		647,217	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
32,323				2,447,739		2,447,739	1
5,692				246,959		246,959	2
7,627				299,787		299,787	3
5,450				425,407		425,407	4
8,746				678,116		678,116	5
6,988				469,447		469,447	6
3,534				217,033		217,033	7
4,977				335,568		335,568	8
9,763				654,436		654,436	9
5,825				417,192		417,192	10
34,010				1,815,196		1,815,196	11
7,645				495,309		495,309	12
10				655		655	13
3				98		98	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
5,674				374,774		374,774	1
314				12,852		12,852	2
6,892				460,956		460,956	3
7,171				551,066		551,066	4
1,777				119,431		119,431	5
8,984				601,346		601,346	6
8,904				633,557		633,557	7
4,453				298,910		298,910	8
136				4,357		4,357	9
107				6,073		6,073	10
							11
123				8,262		8,262	12
12				370		370	13
2				73		73	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2				69		69	1
5				143		143	2
6,170				415,326		415,326	3
90				6,844		6,844	4
25				1,448		1,448	5
7,092				461,519		461,519	6
3				98		98	7
14,600				455,082		455,082	8
877				56,539		56,539	9
3,470				231,286		231,286	10
20				638		638	11
6				193		193	12
7,457				435,475		435,475	13
9,004				602,792		602,792	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
6,995				288,311		288,311	1
101				3,220		3,220	2
6,626				297,676		297,676	3
13,434				418,945		418,945	4
1,807				55,531		55,531	5
8,449				572,149		572,149	6
14				750		750	7
8,191				575,001		575,001	8
222				7,096		7,096	9
59,803				4,097,447		4,097,447	10
1,140				75,394		75,394	11
4,935				262,786		262,786	12
3,544				236,608		236,608	13
25				1,594		1,594	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
16,774				637,738		637,738	1
7,848				514,050		514,050	2
6				344		344	3
2				57		57	4
13,508				940,164		940,164	5
98				4,065		4,065	6
1				28		28	7
29				938		938	8
5				321		321	9
8,847				688,904		688,904	10
4				138		138	11
6,749				518,656		518,656	12
2				66		66	13
8,849				591,731		591,731	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
14,256				826,848		826,848	1
6,030				406,164		406,164	2
67				2,338		2,338	3
							4
8,973				649,460		649,460	5
6				182		182	6
847				57,089		57,089	7
3,077				206,106		206,106	8
9,018				605,466		605,466	9
8,440				566,796		566,796	10
5				156		156	11
37				1,193		1,193	12
9,113				610,132		610,132	13
1				24		24	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
102				3,064		3,064	1
5,879				398,758		398,758	2
8,599				559,880		559,880	3
5,180				349,755		349,755	4
25,855				1,714,981		1,714,981	5
28,526				1,782,900		1,782,900	6
5,105				346,433		346,433	7
1,232				82,214		82,214	8
6				180		180	9
2,868				204,191		204,191	10
60				3,272		3,272	11
27				1,598		1,598	12
7				377		377	13
2				49		49	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
32				1,780		1,780	1
11,279				696,035		696,035	2
394				26,725		26,725	3
2				63		63	4
7,225				536,676		536,676	5
7,984				620,533		620,533	6
94				3,252		3,252	7
146				4,673		4,673	8
8,870				594,444		594,444	9
8,712				586,221		586,221	10
9,090				613,573		613,573	11
93				5,990		5,990	12
3,404				263,614		263,614	13
3,260				253,716		253,716	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
3,382				225,548		225,548	1
3,767				253,081		253,081	2
3,725				248,882		248,882	3
3,539				236,133		236,133	4
3,876				285,682		285,682	5
74				3,850		3,850	6
8,896				634,604		634,604	7
							8
8				256		256	9
3				93		93	10
3				107		107	11
5				146		146	12
1				11		11	13
9				291		291	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
12				367		367	1
160				6,709		6,709	2
12				393		393	3
3,294				222,141		222,141	4
6				312		312	5
8				212		212	6
2				75		75	7
42				1,316		1,316	8
9,304				605,964		605,964	9
4,313				301,487		301,487	10
5,361				374,762		374,762	11
19,138				1,033,436		1,033,436	12
4,150				290,076		290,076	13
9,001				577,858		577,858	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
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8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
7,486				502,597		502,597	1
3,956				265,899		265,899	2
117				3,757		3,757	3
9,074				605,763		605,763	4
3				77		77	5
8,186				556,862		556,862	6
7,589				590,091		590,091	7
71				2,267		2,267	8
1,525				118,366		118,366	9
5,032				372,368		372,368	10
127,540				7,361,851		7,361,851	11
93				3,828		3,828	12
9,198				619,968		619,968	13
49				3,318		3,318	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
6,442				471,891		471,891	1
1,323				89,046		89,046	2
9,567				643,629		643,629	3
5,679				381,264		381,264	4
9				507		507	5
5,524				370,156		370,156	6
8,582				573,894		573,894	7
8,645				661,589		661,589	8
9,239				617,713		617,713	9
8,476				580,083		580,083	10
8,059				628,052		628,052	11
909				28,424		28,424	12
16				1,023		1,023	13
3,705				249,059		249,059	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
179				5,730		5,730	1
8,359				647,553		647,553	2
5,801				300,242		300,242	3
11,904				601,248		601,248	4
							5
11,970				614,177		614,177	6
18,832				902,700		902,700	7
1,253				41,132		41,132	8
894				30,217		30,217	9
5,116				169,341		169,341	10
1,771				59,741		59,741	11
3,675				121,634		121,634	12
225				7,194		7,194	13
25				786		786	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
23				730		730	1
3,530				231,693		231,693	2
1,650				52,701		52,701	3
9,182				648,457		648,457	4
							5
2,030				128,259		128,259	6
8,753				580,279		580,279	7
9,517				639,232		639,232	8
3				102		102	9
11,578				479,447		479,447	10
6,424				262,264		262,264	11
1,927				134,455		134,455	12
1,242				38,331		38,331	13
129				5,319		5,319	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
11				345		345	1
41				1,215		1,215	2
6,673				432,034		432,034	3
3				91		91	4
3				82		82	5
5				139		139	6
536				35,539		35,539	7
4				114		114	8
4,005				268,090		268,090	9
7,827				338,477		338,477	10
3				82		82	11
5,403				358,274		358,274	12
773				37,253		37,253	13
9,488				635,740		635,740	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
162				5,623		5,623	1
2				49		49	2
136,368				8,493,178		8,493,178	3
210				14,080		14,080	4
29,851				1,638,358		1,638,358	5
7,745				500,839		500,839	6
31				984		984	7
3,511				238,114		238,114	8
4,291				137,038		137,038	9
8,386				565,191		565,191	10
8,775				590,478		590,478	11
9,545				639,342		639,342	12
7,972				536,676		536,676	13
9,153				655,718		655,718	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,235				86,070		86,070	1
				2		2	2
2,595				134,999		134,999	3
9,112				616,088		616,088	4
1,340				82,571		82,571	5
9				275		275	6
9,338				625,054		625,054	7
9,529				679,363		679,363	8
2,328				75,901		75,901	9
9,103				611,994		611,994	10
12				396		396	11
8,467				559,893		559,893	12
25				796		796	13
9,789				663,675		663,675	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
7				210		210	1
6				187		187	2
246				7,757		7,757	3
15,145				1,026,861		1,026,861	4
							5
408				27,559		27,559	6
6				176		176	7
5				145		145	8
							9
2				48		48	10
10				321		321	11
9,349				628,682		628,682	12
4				141		141	13
12,076				763,885		763,885	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

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6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
9,523				619,270		619,270	1
26				816		816	2
1,204				79,866		79,866	3
8,527				665,221		665,221	4
1,405				98,669		98,669	5
363				23,521		23,521	6
4,865				307,123		307,123	7
396				31,524		31,524	8
5				160		160	9
8,392				551,463		551,463	10
784				50,148		50,148	11
31				969		969	12
8,354				644,064		644,064	13
212				6,779		6,779	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2				43		43	1
1				38		38	2
3,682				2,605		2,605	3
8,095				552,206		552,206	4
8,156				625,062		625,062	5
3,749				253,031		253,031	6
5,765				317,358		317,358	7
3,875				223,191		223,191	8
81				2,550		2,550	9
4				128		128	10
3				94		94	11
13,424				880,171		880,171	12
72				2,302		2,302	13
5,323				359,150		359,150	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,370				288,306		288,306	1
3,553				237,536		237,536	2
31				1,778		1,778	3
							4
							5
1,065				46,000		46,000	6
				21,984		21,984	7
				11,770		11,770	8
							9
	3,679,024	3,560,392	-733,805	3,025,440		2,291,635	10
68,068	3,017,192	2,919,900	-601,799	1,595,311		993,512	11
							12
	1,226,342	1,186,800	-244,603	-219,044		-463,647	13
		5,796		-1,180,192		-1,180,192	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
							1
-1,963		1,963		-41,275		-41,275	2
-1,610		1,610		-33,850		-33,850	3
							4
-654		654		-13,759		-13,759	5
							6
300,145			8,373,980	6,892,460		15,266,440	7
							8
			-18,734	-159,807		-178,541	9
							10
1,275				42,255		42,255	11
579,749			10,668,300	18,816,417		29,484,717	12
							13
				8,923		8,923	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
				-1		-1	2
							3
			206,116			206,116	4
5,388,471				131,727,240		131,727,240	5
-8,697				54,312,636		54,312,636	6
							7
							8
							9
							10
							11
							12
							13
							14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
1,800				59,650		59,650	1
							2
50				1,400		1,400	3
10,093				383,690		383,690	4
82,424	9		2,195,071	2,118,563		4,313,634	5
							6
				-6,880		-6,880	7
							8
							9
							10
733,253				28,760,276		28,760,276	11
3,200				95,905		95,905	12
							13
51,355				2,373,025		2,373,025	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
			56,213			56,213	1
800				41,600		41,600	2
							3
503,380				12,022,982		12,022,982	4
							5
266,943				8,529,731		8,529,731	6
140,160			3,999,537	3,308,395		7,307,932	7
							8
			-30,282	-74,406		-104,688	9
							10
140,334				3,235,884		3,235,884	11
556,050				17,787,539		17,787,539	12
				-175,671		-175,671	13
				3,304		3,304	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
							1
73,925				2,134,540		2,134,540	2
10,277				298,582		298,582	3
2,295				83,800		83,800	4
							5
			7,008			7,008	6
			238,272			238,272	7
							8
1,813				54,607		54,607	9
							10
1,525				22,293		22,293	11
18,215				409,281		409,281	12
				136,545		136,545	13
2,036				18,181		18,181	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

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4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES MegaWatt Hours Received (h)	POWER EXCHANGES MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	COST/SETTLEMENT OF POWER Energy Charges ($) (k)	COST/SETTLEMENT OF POWER Other Charges ($) (l)	COST/SETTLEMENT OF POWER Total (j+k+l) of Settlement ($) (m)	Line No.
7,410				130,071		130,071	1
							2
52,419				1,351,051		1,351,051	3
							4
	3,104			681		681	5
	-6,731			-234,665		-234,665	6
	569			17,162		17,162	7
	-2,129			-189,548		-189,548	8
	-2,107			-66,943		-66,943	9
	216			1,181,753		1,181,753	10
	-4,422			-484,365		-484,365	11
	1,909			-162,259		-162,259	12
	-604			-16,273		-16,273	13
	-8,752			-333,302		-333,302	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
							1
				-9,686		-9,686	2
				24		24	3
				-1,332		-1,332	4
				-211		-211	5
				-5,703		-5,703	6
				-62		-62	7
				5,267		5,267	8
				114		114	9
				-71,823		-71,823	10
				-944		-944	11
				-6,781		-6,781	12
				-512		-512	13
				-11,522		-11,522	14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

PURCHASED POWER(Account 555) (Continued)
(Including power exchanges)

AD - for out-of-period adjustment. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting years. Provide an explanation in a footnote for each adjustment.

4. In column (c), identify the FERC Rate Schedule Number or Tariff, or, for non-FERC jurisdictional sellers, include an appropriate designation for the contract. On separate lines, list all FERC rate schedules, tariffs or contract designations under which service, as identified in column (b), is provided.
5. For requirements RQ purchases and any type of service involving demand charges imposed on a monnthly (or longer) basis, enter the monthly average billing demand in column (d), the average monthly non-coincident peak (NCP) demand in column (e), and the average monthly coincident peak (CP) demand in column (f). For all other types of service, enter NA in columns (d), (e) and (f). Monthly NCP demand is the maximum metered hourly (60-minute integration) demand in a month. Monthly CP demand is the metered demand during the hour (60-minute integration) in which the supplier's system reaches its monthly peak. Demand reported in columns (e) and (f) must be in megawatts. Footnote any demand not stated on a megawatt basis and explain.
6. Report in column (g) the megawatthours shown on bills rendered to the respondent. Report in columns (h) and (i) the megawatthours of power exchanges received and delivered, used as the basis for settlement. Do not report net exchange.
7. Report demand charges in column (j), energy charges in column (k), and the total of any other types of charges, including out-of-period adjustments, in column (l). Explain in a footnote all components of the amount shown in column (l). Report in column (m) the total charge shown on bills received as settlement by the respondent. For power exchanges, report in column (m) the settlement amount for the net receipt of energy. If more energy was delivered than received, enter a negative amount. If the settlement amount (l) include credits or charges other than incremental generation expenses, or (2) excludes certain credits or charges covered by the agreement, provide an explanatory footnote.
8. The data in column (g) through (m) must be totalled on the last line of the schedule. The total amount in column (g) must be reported as Purchases on Page 401, line 10. The total amount in column (h) must be reported as Exchange Received on Page 401, line 12. The total amount in column (i) must be reported as Exchange Delivered on Page 401, line 13.
9. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				-73,069		-73,069	1
				-282		-282	2
				-4,621		-4,621	3
				-90		-90	4
							5
	142,622	144,900					6
							7
							8
							9
							10
							11
							12
							13
							14
10,690,044	8,046,242	7,822,015	24,115,274	404,033,022		428,148,296	

FOOTNOTE DATA

Schedule Page: 326 Line No.: 1 Column: c

(1) This company is a Qualifying Facility (QF) pursuant to PURPA. Rates for purchase from QF's are set by the North Carolinas Utilities Commission and the South Carolinas Public Service Commission and therefore have no designated FERC Rate Schedule or Tariff Number.

Schedule Page: 326.22 Line No.: 14 Column: c

(2) Purchase from this company is done pursuant to a Market Rate tariff of purchaser.

Schedule Page: 326.26 Line No.: 9 Column: c

(3) Settlement for imbalance exchange.

Schedule Page: 326.27 Line No.: 5 Column: c

(4) Settlement for imbalance exchange.

Schedule Page: 326.29 Line No.: 6 Column: c

(5) The Operation Regulation refers to MHWs scheduled in versus MHWs scheduled out of the Duke Balancing Authority.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Brookfield Energy Marketing LP	Various	Various	LFP
2	Brookfield Energy Marketing LP	Various	Various	LFP
3	Brookfield Energy Marketing LP	Various	Various	OS
4	Brookfield Energy Marketing LP	Various	Various	SFP
5	Brookfield Renewable Trading and Marketing	Various	Various	OS
6	Brookfield Renewable Trading and Marketing	Various	Various	SFP
7	Carolina Power & Light	Various	Various	LFP
8	Carolina Power & Light	Various	Various	LFP
9	Carolina Power & Light	Various	Various	LFP
10	Carolina Power & Light	Various	Various	LFP
11	Carolina Power & Light	Various	Various	LFP
12	Carolina Power & Light	Various	Various	OS
13	Carolina Power & Light	Various	Various	SFP
14	EDF Trading North America	Various	Various	OS
15	EDF Trading North America	Various	Various	SFP
16	Endure Energy LLC	Various	Various	OS
17	Exelon Power Team	Various	Various	OS
18	Exelon Power Team	Various	Various	SFP
19	Florida Power Corp	Various	Various	OS
20	FPLEMT (Regulated Marketing Arm of FP&L)	Various	Various	OS
21	Macquarie Energy LLC	Various	Various	OS
22	Macquarie Energy LLC	Various	Various	SFP
23	Mercuria Energy America Inc	Various	Various	OS
24	Mercuria Energy America Inc	Various	Various	SFP
25	Morgan Stanley Capital Group Inc	Various	Various	OS
26	Morgan Stanley Capital Group Inc	Various	Various	SFP
27	NC Electric Membership Corporation	Various	Various	LFP
28	NC Electric Membership Corporation	Various	Various	LFP
29	NC Electric Membership Corporation	Various	Various	LFP
30	NC Electric Membership Corporation	Various	Various	LFP
31	NC Electric Membership Corporation	Various	Various	LFP
32	NC Electric Membership Corporation	Various	Various	OS
33	NC Electric Membership Corporation	Various	Various	SFP
34	NCMPA	Various	Various	OS
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	NCMPA	Various	Various	SFP
2	NTE Carolinas LLC	Various	Various	LFP
3	NTE Carolinas LLC	Various	Various	LFP
4	NTE Carolinas LLC	Various	Various	LFP
5	NTE Carolinas LLC	Various	Various	OS
6	NTE Carolinas LLC	Various	Various	SFP
7	Rainbow Energy Marketing	Various	Various	OS
8	Rainbow Energy Marketing	Various	Various	SFP
9	South Carolina Electric & Gas Company	Various	Various	AD
10	South Carolina Public Service Authority - P2P	Various	Various	LFP
11	South Carolina Public Service Authority - P2P	Various	Various	OS
12	South Carolina Public Service Authority - P2P	Various	Various	SFP
13	Southern Wholesale	Various	Various	OS
14	Southern Wholesale	Various	Various	SFP
15	Tennessee Valley Authority	Various	Various	OS
16	The Energy Authority	Various	Various	OS
17	The Energy Authority	Various	Various	SFP
18	Westar Energy	Various	Various	OS
19	Westar Energy	Various	Various	SFP
20	Point to Point MWH(s) for all entries above			
21	Blue Ridge Electric Membership Corporation	Various	Various	FNO
22	Central Electric Power Cooperative Inc.	Various	Various	FNO
23	City of Concord	Various	Various	FNO
24	City of Kings Mountain	Various	Various	FNO
25	City of Seneca	Various	Various	FNO
26	EnergyUnited Electric Membership	Various	Various	FNO
27	Greenwood Commissioners of Public Works	Various	Various	FNO
28	Haywood Electric Membership Corporation	Various	Various	FNO
29	Lockhart Power Company	Various	Various	FNO
30	Macquarie Energy LLC	Various	Various	FNO
31	NC Electric Membership Corporation	Various	Various	FNO
32	NCMPA	Various	Various	FNO
33	Piedmont Electric Membership Corporation	Various	Various	FNO
34	Piedmont Municipal Power Agency	Various	Various	FNO
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456.1)
(Including transactions referred to as 'wheeling')

1. Report all transmission of electricity, i.e., wheeling, provided for other electric utilities, cooperatives, other public authorities, qualifying facilities, non-traditional utility suppliers and ultimate customers for the quarter.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in column (a), (b) and (c).
3. Report in column (a) the company or public authority that paid for the transmission service. Report in column (b) the company or public authority that the energy was received from and in column (c) the company or public authority that the energy was delivered to. Provide the full name of each company or public authority. Do not abbreviate or truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation the respondent has with the entities listed in columns (a), (b) or (c)
4. In column (d) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO - Firm Network Service for Others, FNS - Firm Network Transmission Service for Self, LFP - "Long-Term Firm Point to Point Transmission Service, OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point to Point Transmission Reservation, NF - non-firm transmission service, OS - Other Transmission Service and AD - Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classifi-cation (d)
1	Rutherford Electric Membership Corporation	Various	Various	FNO
2	SCE&G COMPANY	Various	Various	FNO
3	South Carolina Public Service Authority -	Various	Various	FNO
4	Southern Power Companyÿ- Rowan Plant	Various	Various	FNO
5	Town of Dallas	Various	Various	FNO
6	Town of Due West	Various	Various	FNO
7	Town of Forest City	Various	Various	FNO
8	Town of Highlands	Various	Various	FNO
9	Town of Prosperity	Various	Various	FNO
10	US Department of Energy	Various	Various	FNO
11	Western Carolina University			
12	Revenue Accrual			
13				
14				
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Various	Various	Various	99			1
Various	Various	Various	200			2
Various	Various	Various				3
Various	Various	Various				4
Various	Various	Various				5
Various	Various	Various				6
Various	Various	Various	100			7
Various	Various	Various	150			8
Various	Various	Various	150			9
Various	Various	Various	300			10
Various	Various	Various	850			11
Various	Various	Various				12
Various	Various	Various				13
Various	Various	Various				14
Various	Various	Various				15
Various	Various	Various				16
Various	Various	Various				17
Various	Various	Various				18
Various	Various	Various				19
Various	Various	Various				20
Various	Various	Various				21
Various	Various	Various				22
Various	Various	Various				23
Various	Various	Various				24
Various	Various	Various				25
Various	Various	Various				26
Various	Various	Various	100			27
Various	Various	Various	50			28
Various	Various	Various	50			29
Various	Various	Various	50			30
Various	Various	Various	55			31
Various	Various	Various				32
Various	Various	Various				33
Various	Various	Various				34
			3,676	**37,962,028**	**37,894,910**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
Various	Various	Various				1
Various	Various	Various	500			2
Various	Various	Various	500			3
Various	Various	Various	500			4
Various	Various	Various				5
Various	Various	Various				6
Various	Various	Various				7
Various	Various	Various				8
Various	Various	Various				9
Various	Various	Various	22			10
Various	Various	Various				11
Various	Various	Various				12
Various	Various	Various				13
Various	Various	Various				14
Various	Various	Various				15
Various	Various	Various				16
Various	Various	Various				17
Various	Various	Various				18
Various	Various	Various				19
				15,591,780	15,524,903	20
	Various	Various		1,407,278	1,407,278	21
	Various	Various		4,014,236	4,014,236	22
	Various	Various		990,641	990,641	23
	Various	Various		154,901	154,901	24
	Various	Various		158,109	158,109	25
	Various	Various		2,841,216	2,841,216	26
	Various	Various		319,341	319,341	27
	Various	Various		130,995	130,995	28
	Various	Various		238,925	238,925	29
	Various	Various				30
	Various	Various		2,162,734	2,162,734	31
	Various	Various		5,412,980	5,412,980	32
	Various	Various		406,569	406,569	33
	Various	Various		2,431,144	2,431,144	34
			3,676	**37,962,028**	**37,894,910**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456)(Continued)
(Including transactions reffered to as 'wheeling')

5. In column (e), identify the FERC Rate Schedule or Tariff Number, On separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (d), is provided.
6. Report receipt and delivery locations for all single contract path, "point to point" transmission service. In column (f), report the designation for the substation, or other appropriate identification for where energy was received as specified in the contract. In column (g) report the designation for the substation, or other appropriate identification for where energy was delivered as specified in the contract.
7. Report in column (h) the number of megawatts of billing demand that is specified in the firm transmission service contract. Demand reported in column (h) must be in megawatts. Footnote any demand not stated on a megawatts basis and explain.
8. Report in column (i) and (j) the total megawatthours received and delivered.

FERC Rate Schedule of Tariff Number (e)	Point of Receipt (Subsatation or Other Designation) (f)	Point of Delivery (Substation or Other Designation) (g)	Billing Demand (MW) (h)	TRANSFER OF ENERGY		Line No.
				MegaWatt Hours Received (i)	MegaWatt Hours Delivered (j)	
	Various	Various		1,364,313	1,364,313	1
	Various	Various		5,653	5,653	2
	Various	Various		8,752	8,752	3
	Various	Various				4
	Various	Various		74,570	74,570	5
	Various	Various		13,726	13,726	6
	Various	Various		114,654	114,654	7
	Various	Various		50,382	50,382	8
	Various	Various		12,266	12,266	9
	Various	Various		11,436	11,195	10
				45,427	45,427	11
						12
						13
						14
						15
						16
						17
						18
						19
						20
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						34
			3,676	**37,962,028**	**37,894,910**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
3,982,667			3,982,667	1
1,971,420	20,182		1,991,602	2
-433,197		5,365	-427,832	3
		-850,728	-850,728	4
		68	68	5
	5,551	1,354,465	1,360,017	6
				7
				8
				9
				10
				11
		251,659	251,659	12
		-14,101	-14,101	13
-9,187		122,897	113,710	14
		329	329	15
-812	6,097	18,200	23,485	16
-119,010		401,435	282,425	17
		868,261	868,261	18
		31,619	31,619	19
		1,831	1,831	20
-387,007	138,602	768,430	520,024	21
	1,480,726	5,733,763	7,214,488	22
-17,607		212,322	194,715	23
		73,493	73,493	24
-87,947		952,751	864,804	25
		497,703	497,703	26
				27
1,012,625			1,012,625	28
				29
1,012,625			1,012,625	30
				31
		161,061	161,061	32
		62,757	62,757	33
		1,624,994	1,624,994	34
64,242,648	**1,651,401**	**33,312,083**	**99,206,133**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
		853,517	853,517	1
				2
				3
				4
-206,450	243	379,067	172,860	5
		2,262,682	2,262,682	6
-3,955		86,638	82,683	7
		8,900	8,900	8
-508			-508	9
				10
-43,315		539,558	496,243	11
		54,901	54,901	12
-362,650		4,901,807	4,539,157	13
		39,150	39,150	14
		29	29	15
-11,485		96,622	85,137	16
				17
-6,641		37,394	30,753	18
		13,115	13,115	19
				20
3,300,742		1,123,818	4,424,560	21
10,514,850		3,525,190	14,040,040	22
2,352,335		795,522	3,147,857	23
347,973		117,259	465,232	24
401,806		83,552	485,358	25
7,513,287		1,568,019	9,081,306	26
760,264		257,777	1,018,041	27
329,154		111,774	440,928	28
837,957		284,414	1,122,370	29
				30
5,923,735		224,802	6,148,536	31
10,910,524		1,524,374	12,434,897	32
1,116,068		379,949	1,496,018	33
5,868,715		962,534	6,831,250	34
64,242,648	**1,651,401**	**33,312,083**	**99,206,133**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY FOR OTHERS (Account 456) (Continued)
(Including transactions reffered to as 'wheeling')

9. In column (k) through (n), report the revenue amounts as shown on bills or vouchers. In column (k), provide revenues from demand charges related to the billing demand reported in column (h). In column (l), provide revenues from energy charges related to the amount of energy transferred. In column (m), provide the total revenues from all other charges on bills or vouchers rendered, including out of period adjustments. Explain in a footnote all components of the amount shown in column (m). Report in column (n) the total charge shown on bills rendered to the entity Listed in column (a). If no monetary settlement was made, enter zero (11011) in column (n). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
10. The total amounts in columns (i) and (j) must be reported as Transmission Received and Transmission Delivered for annual report purposes only on Page 401, Lines 16 and 17, respectively.
11. Footnote entries and provide explanations following all required data.

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
3,710,492		1,260,810	4,971,302	1
15,946		5,362	21,310	2
-64,949		2,089	-62,860	3
-55		-725,540	-725,595	4
164,521		55,790	220,311	5
30,795		10,452	41,247	6
242,295		82,365	324,661	7
116,352		39,685	156,038	8
24,258		8,233	32,491	9
65,041		21,984	87,025	10
117,392		39,915	157,306	11
3,353,584			3,353,584	12
				13
				14
				15
				16
				17
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				34
64,242,648	**1,651,401**	**33,312,083**	**99,206,133**	

FOOTNOTE DATA

Schedule Page: 328.2 Line No.: 12 Column: a

Accrue for Mutually Agreed Upon Item - $63,809

Accrue Storm Recovery in 2018 OATT - ($1,715,001)

Accrue CTA Asset Adjustment - $545,687

Accrue for Page 227 M&S Inventory Refund - $2,439,768

Accrue for Federal Tax Change - $2,022,055

Q2 Invoice correction - ($2,739)

Rounding - $5

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

1. Report in Column (a) the Transmission Owner receiving revenue for the transmission of electricity by the ISO/RTO.
2. Use a separate line of data for each distinct type of transmission service involving the entities listed in Column (a).
3. In Column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNO – Firm Network Service for Others, FNS – Firm Network Transmission Service for Self, LFP – Long-Term Firm Point-to-Point Transmission Service, OLF – Other Long-Term Firm Transmission Service, SFP – Short-Term Firm Point-to-Point Transmission Reservation, NF – Non-Firm Transmission Service, OS – Other Transmission Service and AD- Out-of-Period Adjustments. Use this code for any accounting adjustments or "true-ups" for service provided in prior reporting periods. Provide an explanation in a footnote for each adjustment. See General Instruction for definitions of codes.
4. In column (c) identify the FERC Rate Schedule or tariff Number, on separate lines, list all FERC rate schedules or contract designations under which service, as identified in column (b) was provided.
5. In column (d) report the revenue amounts as shown on bills or vouchers.
6. Report in column (e) the total revenues distributed to the entity listed in column (a).

Line No.	Payment Received by (Transmission Owner Name) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Total Revenue by Rate Schedule or Tarirff (d)	Total Revenue (e)
1					
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
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34					
35					
36					
37					
38					
39					
40	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	NCMPA	OS			54,831			54,831
2	NCEMC	OS			45,402			45,402
3	Energy United	OS			113,814			113,814
4	Carolina Power & Light	SFP				200,353	9,412	209,765
5	Central	OS			138,300			138,300
6	Carolilna Power & Light	NF				2,636,801	93,950	2,730,751
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL				352,347	2,837,154	103,362	3,292,863

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	1,095,644
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	2,974,548
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	98,467
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	-33,987,865
6	Dues and Subscriptions to various organizations:	
7	Agribusiness Henderson County	500
8	Alamance County CoC	1,100
9	American Nuclear Society	7,200
10	American Society of Corporate Executives	1,742
11	Anderson Area CoC	2,562
12	Asociation of Corporate Contributions	-2,178
13	Baker Botts, LLP	10,365
14	Belmont CoC	810
15	Burke County CoC	1,940
16	Business for Social Responsibility	11,497
17	Cabarrus Regional CoC	3,300
18	Caldwell County CoC	2,500
19	Catawba County CoC	5,000
20	CDP North America, Inc.	5,191
21	Chamber of Commerce of the USA	69,680
22	Chapel Hill Carrboro CoC	8,811
23	CharIN	5,609
24	Charlotte CoC	9,250
25	Charlotte Regional Business Alliance	50,000
26	Cheraw CoC	625
27	Cherokee County CoC (NC)	2,500
28	Chester County CoC	1,500
29	Clemson Area CoC	1,918
30	Cleveland County CoC	872
31	Coal Utilization Research Council	2,613
32	Downtown Winston Salem Partnership	500
33	European American CoC	1,000
34	Franklin Area CoC	1,000
35	Gaston Regional CoC	1,452
36	Greater Durham CoC	9,300
37	Greater Easley CoC	982
38	Greater Gaston Development Corporaton	5,250
39	Greater Greer CoC	618
40	Greater Mauldin CoC	550
41	Greater Winstom CoC	11,465
42	Greater York CoC	520
43	Greensboro CoC	12,934
44	Greenville CoC	30,066
45	Henderson County CoC	1,148
46	TOTAL	-25,764,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Henderson County Partners for Economic Progress	1,200
7	Hickory Nut Gorge CoC	500
8	High Point CoC	3,500
9	Hillsborough/Orange County CoC	3,000
10	Jackson County CoC	500
11	Lake Norman CoC	1,670
12	Lancaster County CoC	3,000
13	Lenoir-Rhyne University Business Council	1,500
14	Liberty CoC	932
15	Matthews CoC	770
16	McDowell CoC	685
17	Mounty Airy CoC	1,010
18	North Carolina Agribusiness Council, Inc	4,250
19	North Carolina CoC	72,200
20	Nuclear Waste Strategy Coalition	3,136
21	Palmetto Business Council	1,250
22	Reidsville CoC	585
23	Rotary Club of Durham	860
24	Rotary Club of Greenwood	-1,000
25	Rotary Club of Shelby	800
26	Rotary Club of Stratford	845
27	Rowan County CoC	3,500
28	Sand Hill Group	9,581
29	Scorecard Option C	1,185
30	Simpsonvlille CoC	750
31	SOS Intl, LLC	5,619
32	South Carolina CoC	48,250
33	Spartanburg Area CoC	7,495
34	Stanly County CoC	1,190
35	SustainAbility Transparency Network	6,968
36	Thomasville Area CoC	3,652
37	Union County CoC	1,025
38	Utility Economic Development Association	2,086
39	Wilkes County CoC	1,828
40	York County Regional CoD	7,040
41	Chamber of Commerce (13)	4,713
42	Miscellaneous	-910
43		
44	Transferred Employee Homes	1,785,652
45		
46	TOTAL	-25,764,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
6	Leased Circuit Charges	3,259
7		
8	Director's Fees and Expenses	1,779,113
9		
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45		
46	TOTAL	-25,764,325

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			68,299,228		68,299,228
2	Steam Production Plant	276,559,129	51,093			276,610,222
3	Nuclear Production Plant	283,054,835				283,054,835
4	Hydraulic Production Plant-Conventional	22,775,501				22,775,501
5	Hydraulic Production Plant-Pumped Storage	18,523,790				18,523,790
6	Other Production Plant	90,788,745				90,788,745
7	Transmission Plant	83,529,780				83,529,780
8	Distribution Plant	271,153,050				271,153,050
9	Regional Transmission and Market Operation					
10	General Plant	54,044,871		114,884		54,159,755
11	Common Plant-Electric					
12	TOTAL	1,100,429,701	51,093	68,414,112		1,168,894,906

B. Basis for Amortization Charges

Limited term electric depreciable plant base is $373,898,177, which is the cost of capitalized software and generating plant relicensing. This includes amortized assets which have been fully amortized but not yet retired. Intangible plant is amortized over 3, 5, and 10 years. The generating plant relicensing is amortized over the remaining life of the license.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands) (b)	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. rates (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12							
13							
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FOOTNOTE DATA

Schedule Page: 336 Line No.: 12 Column: a

This section is not being completed for 2019 since it is only required every 5 years unless there is a new depreciation study.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES

1. Report particulars (details) of regulatory commission expenses incurred during the current year (or incurred in previous years, if being amortized) relating to format cases before a regulatory body, or cases in which such a body was a party.
2. Report in columns (b) and (c), only the current year's expenses that are not deferred and the current year's amortization of amounts deferred in previous years.

Line No.	Description (Furnish name of regulatory commission or body the docket or case number and a description of the case) (a)	Assessed by Regulatory Commission (b)	Expenses of Utility (c)	Total Expense for Current Year (b) + (c) (d)	Deferred in Account 182.3 at Beginning of Year (e)
1	North Carolina Utilities Commission:				
2	NCUC Regulatory Fee - Electric	6,724,275		6,724,275	
3	Coal Ash Management Commission Fee per NC				
4	Docket E-7, Sub 989		247,000	247,000	501,666
5	Docket E-7, Sub 1029		210,000	210,000	476,372
6	Docket E-7, Sub 1146		525,160	525,160	6,319,222
7	Docket M-100, Sub 142/ Docket E-7 Sub1146		555,413	555,413	3,181,250
8					
9					
10	Public Service Commission of South Carolina:				
11	SC PSC Fees	3,912,616		3,912,616	
12	Docket 2009-226-E		10,133	10,133	160,638
13	Docket 2011-271-E		15,945	15,945	355,263
14	Docket 2013-59-E		5,000	5,000	653,331
15	Docket 2015-362-E				
16	Docket 2018-319-E		111,598	111,598	
17					
18	Federal Energy Regulatory Commission:				
19	Annual FERC Billing	3,181,535		3,181,535	
20					
21					
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44					
45					
46	TOTAL	13,818,426	1,680,249	15,498,675	11,647,742

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO			Deferred to Account 182.3	Contra Account	Amount	Deferred in Account 182.3 End of Year	Line No.
Department (f)	Account No. (g)	Amount (h)	(i)	(j)	(k)	(l)	
							1
	928	6,724,275					2
							3
					247,000	254,666	4
					210,000	266,372	5
					525,160	5,794,062	6
					555,413	2,625,838	7
							8
							9
							10
	928	3,912,616					11
					10,133	150,505	12
					15,945	339,318	13
					5,000	648,331	14
							15
	928	17	1,338,975		111,581	1,227,394	16
							17
							18
	928	3,181,535					19
							20
							21
							22
							23
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							39
							40
							41
							42
							43
							44
							45
		13,818,443	1,338,975		1,680,232	11,306,486	46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES

1. Describe and show below costs incurred and accounts charged during the year for technological research, development, and demonstration (R, D & D) project initiated, continued or concluded during the year. Report also support given to others during the year for jointly-sponsored projects.(Identify recipient regardless of affiliation.) For any R, D & D work carried with others, show separately the respondent's cost for the year and cost chargeable to others (See definition of research, development, and demonstration in Uniform System of Accounts).
2. Indicate in column (a) the applicable classification, as shown below:

Classifications:

A. Electric R, D & D Performed Internally:
- (1) Generation
  - a. hydroelectric
    - i. Recreation fish and wildlife
    - ii Other hydroelectric
  - b. Fossil-fuel steam
  - c. Internal combustion or gas turbine
  - d. Nuclear
  - e. Unconventional generation
  - f. Siting and heat rejection
- (2) Transmission
  - a. Overhead
  - b. Underground
- (3) Distribution
- (4) Regional Transmission and Market Operation
- (5) Environment (other than equipment)
- (6) Other (Classify and include items in excess of $50,000.)
- (7) Total Cost Incurred

B. Electric, R, D & D Performed Externally:
- (1) Research Support to the electrical Research Council or the Electric Power Research Institute

Line No.	Classification (a)	Description (b)
1	A. Electric R, D&D Performed Internally:	
2		
3	(3) Distribution:	Research & Development Administration Costs
4		
5	(6) Other:	Other (Less than $50K each)
6		
7	(7) TOTAL ELECTRIC R, D&D PERFORMED INTERNALLY	
8		
9		
10	B. Electric R, D&D Performed Externally:	
11		
12	(1) Research Support to:	
13	Electric Power Research Institute	Electric Power Research Institute Memberships
14		EPRI Nuclear Cofunds
15		Steam & Power Delivery Cofund
16		Biofouling Study
17		Other (Less than $50K each)
18		
19		Alternative Energy (Advanced Energy Resc.)
20		Centre for Energy Advancement through Technological Innovation
21		Electric Power Research Institute
22		UNC Charlotte
23		Georgia Tech Research Group
24		Other (Less than $50K each)
25		
26		
27	TOTAL ELECTRIC R, D&D PERFORMED EXTERNALLY	
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		
38		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $50,000 or more, briefly describing the specific area of R, D & D (such as safety, corrosion control, pollution, automation, measurement, insulation, type of appliance, etc.). Group items under $50,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR		Unamortized Accumulation (g)	Line No.
		Account (e)	Amount (f)		
					1
					2
237,128		930.7	237,128		3
					4
					5
					6
237,128			237,128		7
					8
					9
					10
					11
					12
	5,944,498	Various	5,944,498		13
	1,390,247	Various	1,390,247		14
	135,000	Various	135,000		15
	77,600	524.0	77,600		16
	143,427	Various	143,427		17
					18
	2,091,774	930.8	2,091,774		19
	162,050	930.7	162,050		20
	50,000	930.7	50,000		21
	235,596	930.7	235,596		22
	168,000	930.7	168,000		23
	30,000	930.7	30,000		24
					25
					26
	10,428,192		10,428,192		27
					28
					29
					30
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					36
					37
					38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES

Report below the distribution of total salaries and wages for the year. Segregate amounts originally charged to clearing accounts to Utility Departments, Construction, Plant Removals, and Other Accounts, and enter such amounts in the appropriate lines and columns provided. In determining this segregation of salaries and wages originally charged to clearing accounts, a method of approximation giving substantially correct results may be used.

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
1	Electric			
2	Operation			
3	Production	303,456,920		
4	Transmission	13,365,725		
5	Regional Market			
6	Distribution	31,274,824		
7	Customer Accounts	33,803,350		
8	Customer Service and Informational	8,386,750		
9	Sales	9,268,108		
10	Administrative and General	176,255,555		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	575,811,232		
12	Maintenance			
13	Production	181,759,758		
14	Transmission	8,849,124		
15	Regional Market			
16	Distribution	34,378,208		
17	Administrative and General	270,513		
18	TOTAL Maintenance (Total of lines 13 thru 17)	225,257,603		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	485,216,678		
21	Transmission (Enter Total of lines 4 and 14)	22,214,849		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	65,653,032		
24	Customer Accounts (Transcribe from line 7)	33,803,350		
25	Customer Service and Informational (Transcribe from line 8)	8,386,750		
26	Sales (Transcribe from line 9)	9,268,108		
27	Administrative and General (Enter Total of lines 10 and 17)	176,526,068		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	801,068,835	4,536,759	805,605,594
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

DISTRIBUTION OF SALARIES AND WAGES (Continued)

Line No.	Classification (a)	Direct Payroll Distribution (b)	Allocation of Payroll charged for Clearing Accounts (c)	Total (d)
48	Distribution			
49	Administrative and General			
50	TOTAL Maint. (Enter Total of lines 43 thru 49)			
51	Total Operation and Maintenance			
52	Production-Manufactured Gas (Enter Total of lines 31 and 43)			
53	Production-Natural Gas (Including Expl. and Dev.) (Total lines 32,			
54	Other Gas Supply (Enter Total of lines 33 and 45)			
55	Storage, LNG Terminaling and Processing (Total of lines 31 thru			
56	Transmission (Lines 35 and 47)			
57	Distribution (Lines 36 and 48)			
58	Customer Accounts (Line 37)			
59	Customer Service and Informational (Line 38)			
60	Sales (Line 39)			
61	Administrative and General (Lines 40 and 49)			
62	TOTAL Operation and Maint. (Total of lines 52 thru 61)			
63	Other Utility Departments			
64	Operation and Maintenance			
65	TOTAL All Utility Dept. (Total of lines 28, 62, and 64)	801,068,835	4,536,759	805,605,594
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	279,218,708	22,171,336	301,390,044
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	279,218,708	22,171,336	301,390,044
72	Plant Removal (By Utility Departments)			
73	Electric Plant	34,906,601		34,906,601
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	34,906,601		34,906,601
77	Other Accounts (Specify, provide details in footnote):			
78		4,253,811		4,253,811
79		6,890,537		6,890,537
80		4,200,274		4,200,274
81				
82				
83				
84				
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	15,344,622		15,344,622
96	TOTAL SALARIES AND WAGES	1,130,538,766	26,708,095	1,157,246,861

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

COMMON UTILITY PLANT AND EXPENSES

1. Describe the property carried in the utility's accounts as common utility plant and show the book cost of such plant at end of year classified by accounts as provided by Plant Instruction 13, Common Utility Plant, of the Uniform System of Accounts. Also show the allocation of such plant costs to the respective departments using the common utility plant and explain the basis of allocation used, giving the allocation factors.
2. Furnish the accumulated provisions for depreciation and amortization at end of year, showing the amounts and classifications of such accumulated provisions, and amounts allocated to utility departments using the Common utility plant to which such accumulated provisions relate, including explanation of basis of allocation and factors used.
3. Give for the year the expenses of operation, maintenance, rents, depreciation, and amortization for common utility plant classified by accounts as provided by the Uniform System of Accounts. Show the allocation of such expenses to the departments using the common utility plant to which such expenses are related. Explain the basis of allocation used and give the factors of allocation.
4. Give date of approval by the Commission for use of the common utility plant classification and reference to order of the Commission or other authorization.

DEC has no common Utility Plant & Expenses to report for year ending 2019.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)	14,506,419	17,265,803	17,597,942	17,611,868
3	Net Sales (Account 447)	99	29,265	483,640	499,391
4	Transmission Rights				
5	Ancillary Services				
6	Other Items (list separately)				
7					
8					
9					
10					
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12					
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33					
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35					
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39					
40					
41					
42					
43					
44					
45					
46	TOTAL	14,506,518	17,295,068	18,081,582	18,111,259

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PURCHASES AND SALES OF ANCILLARY SERVICES

Report the amounts for each type of ancillary service shown in column (a) for the year as specified in Order No. 888 and defined in the respondents Open Access Transmission Tariff.

In columns for usage, report usage-related billing determinant and the unit of measure.

(1) On line 1 columns (b), (c), (d), (e), (f) and (g) report the amount of ancillary services purchased and sold during the year.

(2) On line 2 columns (b) (c), (d), (e), (f), and (g) report the amount of reactive supply and voltage control services purchased and sold during the year.

(3) On line 3 columns (b) (c), (d), (e), (f), and (g) report the amount of regulation and frequency response services purchased and sold during the year.

(4) On line 4 columns (b), (c), (d), (e), (f), and (g) report the amount of energy imbalance services purchased and sold during the year.

(5) On lines 5 and 6, columns (b), (c), (d), (e), (f), and (g) report the amount of operating reserve spinning and supplement services purchased and sold during the period.

(6) On line 7 columns (b), (c), (d), (e), (f), and (g) report the total amount of all other types ancillary services purchased or sold during the year. Include in a footnote and specify the amount for each type of other ancillary service provided.

		Amount Purchased for the Year			Amount Sold for the Year		
		Usage - Related Billing Determinant			Usage - Related Billing Determinant		
Line No.	Type of Ancillary Service (a)	Number of Units (b)	Unit of Measure (c)	Dollars (d)	Number of Units (e)	Unit of Measure (f)	Dollars (g)
1	Scheduling, System Control and Dispatch			202,002			5,942,136
2	Reactive Supply and Voltage	19,357	MWH	201,465	10,729,456	MWH	7,474,323
3	Regulation and Frequency Response						593,125
4	Energy Imbalance	14,651,817	MWH	571,519	14,632,870	MWH	1,040,511
5	Operating Reserve - Spinning						1,489,613
6	Operating Reserve - Supplement						1,489,613
7	Other	639,467	MWH	2,341,116	38,501	MWH	942,475
8	Total (Lines 1 thru 7)	15,310,641		3,316,102	25,400,827		18,971,796

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January	23,074	22	8	14,632	4,223	3,736		483	
2	February	21,356	1	8	12,802	3,824	3,736		994	
3	March	20,901	6	6	12,738	3,730	3,736		697	
4	Total for Quarter 1				40,172	11,777	11,208		2,174	
5	April	18,662	30	17	11,525	3,205	3,722		210	
6	May	23,384	29	17	14,912	4,332	3,736		404	
7	June	23,114	24	17	14,434	4,303	3,736		641	
8	Total for Quarter 2				40,871	11,840	11,194		1,255	
9	July	24,377	16	17	15,098	4,579	3,736		964	
10	August	24,254	13	15	15,496	4,607	3,722		429	
11	September	23,820	11	17	15,273	4,454	3,736		357	
12	Total for Quarter 3				45,867	13,640	11,194		1,750	
13	October	23,614	3	17	14,473	4,451	3,736		954	
14	November	21,081	13	8	13,064	3,769	3,736		512	
15	December	21,122	20	8	13,249	3,846	3,686		341	
16	Total for Quarter 4				40,786	12,066	11,158		1,807	
17	Total Year to Date/Year				167,696	49,323	44,754		6,986	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

ELECTRIC ENERGY ACCOUNT

Report below the information called for concerning the disposition of electric energy generated, purchased, exchanged and wheeled during the year.

Line No.	Item (a)	MegaWatt Hours (b)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	79,894,279
3	Steam	22,168,214	23	Requirements Sales for Resale (See instruction 4, page 311.)	7,880,442
4	Nuclear	45,243,922	24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	2,146,057
5	Hydro-Conventional	2,427,405	25	Energy Furnished Without Charge	
6	Hydro-Pumped Storage	3,182,407	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	179,287
7	Other	15,290,909	27	Total Energy Losses	5,298,253
8	Less Energy for Pumping	3,895,927	28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	95,398,318
9	Net Generation (Enter Total of lines 3 through 8)	84,416,930			
10	Purchases	10,690,044			
11	Power Exchanges:				
12	Received	8,046,242			
13	Delivered	7,822,015			
14	Net Exchanges (Line 12 minus line 13)	224,227			
15	Transmission For Other (Wheeling)				
16	Received	37,962,028			
17	Delivered	37,894,910			
18	Net Transmission for Other (Line 16 minus line 17)	67,118			
19	Transmission By Others Losses				
20	TOTAL (Enter Total of lines 9, 10, 14, 18 and 19)	95,398,319			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

MONTHLY PEAKS AND OUTPUT

1. Report the monthly peak load and energy output. If the respondent has two or more power which are not physically integrated, furnish the required information for each non- integrated system.
2. Report in column (b) by month the system's output in Megawatt hours for each month.
3. Report in column (c) by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
4. Report in column (d) by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
5. Report in column (e) and (f) the specified information for each monthly peak load reported in column (d).

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	Day of Month (e)	Hour (f)
29	January	8,434,641	339,390	16,739	22	700
30	February	7,053,265	109,771	15,280	1	700
31	March	7,262,918	205,801	14,866	6	800
32	April	6,758,040	270,015	12,772	3	800
33	May	8,573,939	275,209	16,755	29	1700
34	June	8,123,423	104,600	16,454	24	1700
35	July	9,409,630	139,388	17,594	16	1700
36	August	9,188,454	283,818	17,456	13	1500
37	September	8,567,450	182,619	17,128	11	1700
38	October	7,151,174	76,588	16,867	3	1700
39	November	7,218,928	88,616	15,042	13	800
40	December	7,656,456	70,242	15,033	20	800
41	TOTAL	95,398,318	2,146,057			

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)

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Line No.	Item (a)	Plant Name: *Belews Creek* (b)			Plant Name: *Marshall* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam			Steam		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1974			1965		
4	Year Last Unit was Installed	1975			1970		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2491.20			2119.00		
6	Net Peak Demand on Plant - MW (60 minutes)	2258			2160		
7	Plant Hours Connected to Load	6333			8666		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	2220			2078		
10	When Limited by Condenser Water	2220			2058		
11	Average Number of Employees	159			210		
12	Net Generation, Exclusive of Plant Use - KWh	7123642000			7786940000		
13	Cost of Plant: Land and Land Rights	21738415			5829127		
14	Structures and Improvements	458158729			283803486		
15	Equipment Costs	1918322997			1617618615		
16	Asset Retirement Costs	621184759			792449945		
17	Total Cost	3019404900			2699701173		
18	Cost per KW of Installed Capacity (line 17/5) Including	1212.0283			1274.0449		
19	Production Expenses: Oper, Supv, & Engr	3905832			3475450		
20	Fuel	232032051			275432884		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	18018031			15779279		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1470614			2374637		
26	Misc Steam (or Nuclear) Power Expenses	3044439			2449288		
27	Rents	0			0		
28	Allowances	1155			1701		
29	Maintenance Supervision and Engineering	3992853			3419732		
30	Maintenance of Structures	9011403			5181454		
31	Maintenance of Boiler (or reactor) Plant	12142900			14508470		
32	Maintenance of Electric Plant	3256056			5604042		
33	Maintenance of Misc Steam (or Nuclear) Plant	2509084			1289764		
34	Total Production Expenses	289384418			329516701		
35	Expenses per Net KWh	0.0406			0.0423		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Coal	Oil		Coal	Oil	
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	Tons	Barrels		Tons	Barrels	
38	Quantity (Units) of Fuel Burned	2682740	84994	0	2993623	37655	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12344	137848	0	12563	138027	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	79.450	85.390	0.000	88.580	85.080	0.000
41	Average Cost of Fuel per Unit Burned	82.590	85.318	0.000	89.360	86.390	0.000
42	Average Cost of Fuel Burned per Million BTU	3.345	14.736	0.000	3.557	14.902	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.032	0.032	0.000	0.035	0.035	0.000
44	Average BTU per KWh Net Generation	9366.000	9366.000	0.000	9687.000	9687.000	0.000

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Dan River* (b)	Plant Name: *Dan River* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1949	1968
4	Year Last Unit was Installed	1955	1969
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	1409	0
20	Fuel	1532	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	45670	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	0
26	Misc Steam (or Nuclear) Power Expenses	240011	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	2223	809
30	Maintenance of Structures	383411	0
31	Maintenance of Boiler (or reactor) Plant	26986	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Steam (or Nuclear) Plant	-552	0
34	Total Production Expenses	700690	809
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Buck* (b)	Plant Name: *Buck* (c)
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Steam	Combustion Turbine
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional	Conventional
3	Year Originally Constructed	1953	1970
4	Year Last Unit was Installed	1953	1970
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00	0.00
6	Net Peak Demand on Plant - MW (60 minutes)	0	0
7	Plant Hours Connected to Load	0	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	0	0
10	When Limited by Condenser Water	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - KWh	0	0
13	Cost of Plant: Land and Land Rights	0	0
14	Structures and Improvements	0	0
15	Equipment Costs	0	0
16	Asset Retirement Costs	0	0
17	Total Cost	0	0
18	Cost per KW of Installed Capacity (line 17/5) Including	0	0
19	Production Expenses: Oper, Supv, & Engr	370	106259
20	Fuel	2961	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	0	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	0	11075
26	Misc Steam (or Nuclear) Power Expenses	68637	0
27	Rents	0	0
28	Allowances	0	0
29	Maintenance Supervision and Engineering	48121	4382
30	Maintenance of Structures	236438	1269
31	Maintenance of Boiler (or reactor) Plant	0	0
32	Maintenance of Electric Plant	428	28614
33	Maintenance of Misc Steam (or Nuclear) Plant	0	0
34	Total Production Expenses	356955	151599
35	Expenses per Net KWh	0.0000	0.0000
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)		
38	Quantity (Units) of Fuel Burned	0 0 0	0 0 0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0 0 0	0 0 0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000 0.000 0.000	0.000 0.000 0.000
41	Average Cost of Fuel per Unit Burned	0.000 0.000 0.000	0.000 0.000 0.000
42	Average Cost of Fuel Burned per Million BTU	0.000 0.000 0.000	0.000 0.000 0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000 0.000 0.000	0.000 0.000 0.000
44	Average BTU per KWh Net Generation	0.000 0.000 0.000	0.000 0.000 0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *McGuire* (b)			Plant Name: *Catawba* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Nuclear			Nuclear		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	1981			1985		
4	Year Last Unit was Installed	1984			1986		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	2440.60			2410.20		
6	Net Peak Demand on Plant - MW (60 minutes)	2393			455		
7	Plant Hours Connected to Load	8760			8760		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	2386			458		
10	When Limited by Condenser Water	2316			445		
11	Average Number of Employees	934			814		
12	Net Generation, Exclusive of Plant Use - KWh	19588255000			3770985603		
13	Cost of Plant: Land and Land Rights	754812			779551		
14	Structures and Improvements	713833753			244378404		
15	Equipment Costs	2675458787			618977745		
16	Asset Retirement Costs	-192959611			18734779		
17	Total Cost	3197087741			882870479		
18	Cost per KW of Installed Capacity (line 17/5) Including	1309.9597			366.3059		
19	Production Expenses: Oper, Supv, & Engr	18859009			3707940		
20	Fuel	118218187			22534481		
21	Coolants and Water (Nuclear Plants Only)	3053072			931826		
22	Steam Expenses	18173720			4406531		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	2527950			498209		
26	Misc Steam (or Nuclear) Power Expenses	69580357			13381012		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	20644942			4424282		
30	Maintenance of Structures	4665746			978742		
31	Maintenance of Boiler (or reactor) Plant	30193006			9615720		
32	Maintenance of Electric Plant	20841893			4471338		
33	Maintenance of Misc Steam (or Nuclear) Plant	20619673			4818358		
34	Total Production Expenses	327377555			69768439		
35	Expenses per Net KWh	0.0167			0.0185		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	MBTUs	Nuclear	Grams of	MBTUs	Nuclear	Grams of
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)			Uranium			Uranium
38	Quantity (Units) of Fuel Burned	196509000	0	3158604	197627000	0	2841489
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	37.427	0.000	0.000	41.206	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.602	0.000	0.000	0.592	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.006	0.000	0.000	0.006	0.000
44	Average BTU per KWh Net Generation	0.000	10032.000	0.000	0.000	10086.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: *Dan River* (b)			Plant Name: *Lee CC* (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear	Combined Cycle			Combined Cycle		
2	Type of Constr (Conventional, Outdoor, Boiler, etc)	Conventional			Conventional		
3	Year Originally Constructed	2012			2018		
4	Year Last Unit was Installed	2012			2018		
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	697.85			846.60		
6	Net Peak Demand on Plant - MW (60 minutes)	720			819		
7	Plant Hours Connected to Load	7236			6962		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	718			783		
10	When Limited by Condenser Water	662			786		
11	Average Number of Employees	39			2		
12	Net Generation, Exclusive of Plant Use - KWh	4394062000			5280101000		
13	Cost of Plant: Land and Land Rights	119364			59537		
14	Structures and Improvements	145438487			16091728		
15	Equipment Costs	523562776			585789449		
16	Asset Retirement Costs	0			0		
17	Total Cost	669120627			601940714		
18	Cost per KW of Installed Capacity (line 17/5) Including	958.8316			711.0096		
19	Production Expenses: Oper, Supv, & Engr	3049647			2716496		
20	Fuel	106325108			110146723		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	1107103			3060525		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	1204285			1597979		
30	Maintenance of Structures	952362			1731089		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	6113836			4688313		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	118752341			123941125		
35	Expenses per Net KWh	0.0270			0.0235		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)	Gas			Gas		
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)	MCF			MCF		
38	Quantity (Units) of Fuel Burned	30748409	0	0	31416925	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	1030	0	0	1025	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	3.456	0.000	0.000	3.504	0.000	0.000
41	Average Cost of Fuel per Unit Burned	3.456	0.000	0.000	3.504	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.356	0.000	0.000	3.418	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.025	0.000	0.000	0.024	0.000	0.000
44	Average BTU per KWh Net Generation	7206.000	0.000	0.000	6990.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Line No.	Item (a)	Plant Name: (b)			Plant Name: (c)		
1	Kind of Plant (Internal Comb, Gas Turb, Nuclear						
2	Type of Constr (Conventional, Outdoor, Boiler, etc)						
3	Year Originally Constructed						
4	Year Last Unit was Installed						
5	Total Installed Cap (Max Gen Name Plate Ratings-MW)	0.00			0.00		
6	Net Peak Demand on Plant - MW (60 minutes)	0			0		
7	Plant Hours Connected to Load	0			0		
8	Net Continuous Plant Capability (Megawatts)	0			0		
9	When Not Limited by Condenser Water	0			0		
10	When Limited by Condenser Water	0			0		
11	Average Number of Employees	0			0		
12	Net Generation, Exclusive of Plant Use - KWh	0			0		
13	Cost of Plant: Land and Land Rights	0			0		
14	Structures and Improvements	0			0		
15	Equipment Costs	0			0		
16	Asset Retirement Costs	0			0		
17	Total Cost	0			0		
18	Cost per KW of Installed Capacity (line 17/5) Including	0			0		
19	Production Expenses: Oper, Supv, & Engr	0			0		
20	Fuel	0			0		
21	Coolants and Water (Nuclear Plants Only)	0			0		
22	Steam Expenses	0			0		
23	Steam From Other Sources	0			0		
24	Steam Transferred (Cr)	0			0		
25	Electric Expenses	0			0		
26	Misc Steam (or Nuclear) Power Expenses	0			0		
27	Rents	0			0		
28	Allowances	0			0		
29	Maintenance Supervision and Engineering	0			0		
30	Maintenance of Structures	0			0		
31	Maintenance of Boiler (or reactor) Plant	0			0		
32	Maintenance of Electric Plant	0			0		
33	Maintenance of Misc Steam (or Nuclear) Plant	0			0		
34	Total Production Expenses	0			0		
35	Expenses per Net KWh	0.0000			0.0000		
36	Fuel: Kind (Coal, Gas, Oil, or Nuclear)						
37	Unit (Coal-tons/Oil-barrel/Gas-mcf/Nuclear-indicate)						
38	Quantity (Units) of Fuel Burned	0	0	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	0	0	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	0.000	0.000	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	0.000	0.000	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	0.000	0.000	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.000	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	0.000	0.000	0.000	0.000	0.000	0.000

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: *Allen* (d)			Plant Name: *Lee* (e)			Plant Name: *Lee* (f)			Line No.
Steam			Steam			Combustion Turbine			1
Conventional			Conventional			Conventional			2
1957			1951			2006			3
1961			1958			2007			4
1148.40			0.00			108.00			5
1137			0			98			6
5420			0			160			7
0			0			0			8
1130			173			96			9
1098			170			84			10
99			43			0			11
895019000			-5559000			8153000			12
584264			162649			0			13
173202061			31317455			1533026			14
1156969353			78503826			60873967			15
833560162			0			0			16
2164315840			109983930			62406993			17
1884.6359			0			577.8425			18
1601000			153873			521226			19
39912354			76943			1120254			20
0			0			0			21
4527021			74483			0			22
0			0			0			23
0			0			0			24
1549909			31873			263239			25
1927229			424662			0			26
0			0			0			27
61			0			0			28
1832630			240870			-479989			29
3888971			372487			151568			30
3398897			73343			0			31
1599532			238753			1049559			32
593664			40291			0			33
60831268			1727578			2625857			34
0.0680			-0.3108			0.3221			35
Coal	Oil		Gas			Gas	Oil		36
Tons	Barrels		MCF			MCF	Barrels		37
444075	16417	0	5813	0	0	162861	3279	0	38
11798	137745	0	1021	0	0	1023	138059	0	39
79.850	84.190	0.000	9.841	0.000	0.000	4.857	0.000	0.000	40
83.540	85.068	0.000	9.841	0.000	0.000	4.857	97.753	0.000	41
3.541	14.705	0.000	9.641	0.000	0.000	4.747	16.856	0.000	42
0.043	0.043	0.000	-0.010	0.000	0.000	0.136	0.136	0.000	43
11814.000	11814.000	0.000	-1067.000	0.000	0.000	22771.000	22771.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Cliffside* (d)			Plant Name: *Riverbend* (e)			Plant Name: *Riverbend* (f)			Line No.
Steam			Steam			Combustion Turbine			1
Conventional			Conventional			Conventional			2
1972			1952			1969			3
2012			1954			1969			4
1530.50			0.00			0.00			5
1392			0			0			6
7262			0			0			7
0			0			0			8
1395			0			0			9
1388			0			0			10
115			0			0			11
6368172000			0			0			12
3338075			0			0			13
418683279			39248			0			14
2654173299			705884			0			15
470952625			0			0			16
3547147278			745132			0			17
2317.6395			0			0			18
2903603			917			0			19
211227535			2687			0			20
0			0			0			21
16590306			0			0			22
0			0			0			23
0			0			0			24
2209943			0			0			25
2773674			49517			0			26
0			0			0			27
507			0			0			28
3073712			2294			0			29
3597784			67402			0			30
7778636			1878			0			31
2612326			0			0			32
771256			0			0			33
253539282			124695			0			34
0.0398			0.0000			0.0000			35
Coal	Oil	GAS							36
Tons	Barrels	MCF							37
2008476	21462	11475120	0	0	0	0	0	0	38
12192	138010	1028	0	0	0	0	0	0	39
77.190	84.900	3.688	0.000	0.000	0.000	0.000	0.000	0.000	40
80.980	85.539	3.688	0.000	0.000	0.000	0.000	0.000	0.000	41
3.321	14.757	3.589	0.000	0.000	0.000	0.000	0.000	0.000	42
0.032	0.032	0.032	0.000	0.000	0.000	0.000	0.000	0.000	43
9562.000	9562.000	9562.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Buzzard Roost* (d)			Plant Name: *Lincoln* (e)			Plant Name: *Oconee* (f)			Line No.
Combustion Turbine			Combustion Turbine			Nuclear			1
Conventional			Conventional			Conventional			2
1971			1995			1973			3
1971			1996			1974			4
0.00			1753.60			2666.70			5
0			975			2637			6
0			192			8760			7
0			0			0			8
0			1565			2618			9
0			1193			2554			10
0			11			1013			11
0			24505000			21884681000			12
0			3021923			1504454			13
0			28666868			971189227			14
0			380091461			3503687431			15
0			0			-77290937			16
0			411780252			4399090175			17
0			234.8199			1649.6382			18
0			455131			14226820			19
0			1763659			129965850			20
0			0			3748990			21
0			0			18225568			22
0			0			0			23
0			0			0			24
0			1778343			18268515			25
0			0			89013507			26
0			0			0			27
0			0			0			28
0			872078			26842822			29
0			429335			5095442			30
0			0			24498083			31
0			3561435			15773767			32
0			0			21837804			33
0			8859981			367497168			34
0.0000			0.3616			0.0168			35
			Gas	Oil		MBTUs	Nuclear	Grams of	36
			MCF	Barrels				Uranium	37
0	0	0	400953	2612	0	222273000	0	3581215	38
0	0	0	1030	138139	0	0	0	0	39
0.000	0.000	0.000	3.475	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	3.475	88.017	0.000	0.000	36.291	0.000	41
0.000	0.000	0.000	3.373	15.172	0.000	0.000	0.585	0.000	42
0.000	0.000	0.000	0.066	0.066	0.000	0.000	0.006	0.000	43
0.000	0.000	0.000	17474.000	17474.000	0.000	0.000	10157.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Mill Creek* (d)			Plant Name: *Rockingham* (e)			Plant Name: *Buck* (f)			Line No.
Combustion Turbine			Combustion Turbine			Combined Cycle			1
Conventional			Conventional			Conventional			2
2002			2000			2011			3
2003			2000			2011			4
799.20			977.50			697.85			5
703			898			722			6
291			2004			7336			7
0			0			0			8
757			895			716			9
563			825			668			10
9			12			38			11
73101000			959484000			4392284000			12
5063537			967095			0			13
29823655			3376650			150466684			14
221081214			310316196			553591209			15
0			0			0			16
255968406			314659941			704057893			17
320.2808			321.9028			1008.8957			18
232343			434490			827101			19
3379134			35292633			106970604			20
0			0			0			21
0			0			0			22
0			0			0			23
0			0			0			24
1194895			1735656			1742444			25
0			0			0			26
0			0			0			27
0			0			0			28
431588			685032			556447			29
312214			291468			36561088			30
0			0			0			31
721321			1875100			8488744			32
0			0			0			33
6271495			40314379			155146428			34
0.0858			0.0420			0.0353			35
Gas	Oil		Gas	Oil		Gas			36
MCF	Barrels		MCF	Barrels		MCF			37
952236	1517	0	10270881	2498	0	30391165	0	0	38
1026	137640	0	1033	139834	0	1031	0	0	39
3.316	0.000	0.000	3.406	0.000	0.000	3.518	0.000	0.000	40
3.316	103.737	0.000	3.406	91.174	0.000	3.518	0.000	0.000	41
3.231	17.940	0.000	3.297	15.522	0.000	3.411	0.000	0.000	42
0.045	0.045	0.000	0.037	0.037	0.000	0.024	0.000	0.000	43
13490.000	13490.000	0.000	11074.000	11074.000	0.000	7136.000	0.000	0.000	44

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STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants) *(Continued)*

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Plant Name: *Clemson CHP* (d)	Plant Name: (e)	Plant Name: (f)	Line No.
Combined Heat/Power			1
			2
2019			3
2019			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
4	0	0	11
-243000	0	0	12
0	0	0	13
13132420	0	0	14
40341456	0	0	15
0	0	0	16
53473876	0	0	17
0	0	0	18
851	0	0	19
54702	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
38385	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
93938	0	0	34
-0.3866	0.0000	0.0000	35

GAS									36
MCF									37
13697	0	0	0	0	0	0	0	0	38
1027	0	0	0	0	0	0	0	0	39
3.990	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
3.990	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
3.886	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
-0.225	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
-57885.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

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Plant Name: (d)	Plant Name: (e)	Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
0	0	0	8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
0	0	0	13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0	0	0	21
0	0	0	22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

									36
									37
0	0	0	0	0	0	0	0	0	38
0	0	0	0	0	0	0	0	0	39
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	40
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	41
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	42
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	43
0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	44

FOOTNOTE DATA

Schedule Page: 403 Line No.: -1 Column: e

Lee Units 1 and 2 retired 11-7-2014. Lee 3 was converted from coal burning to gas burning effective December 2014.

Schedule Page: 403 Line No.: 11 Column: f

Remote control operation from Lee Steam Station.

Schedule Page: 402 Line No.: 20 Column: b

Belews Creek Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 20 Column: c

Marshall Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: d

Allen Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 403 Line No.: 20 Column: e

Lee Unit 3 Steam Plant has been converted to operate using natural gas. The fuel consumed now relates to natural gas.

Schedule Page: 402.1 Line No.: -1 Column: b

Dan River Steam was retired 4/1/2012.

Schedule Page: 402.1 Line No.: -1 Column: c

Dan River Combustion Turbine was fully retired 10/1/2012.

Schedule Page: 403.1 Line No.: -1 Column: f

Riverbend Combustion Turbine was retired 10/1/2012.

Schedule Page: 403.1 Line No.: 3 Column: d

Cliffside Units 1-4 were retired 10/1/2011.

Schedule Page: 403.1 Line No.: 3 Column: e

Dates do not reflect units which were retired prior to 1-1-01. Riverbend 4, 5, 6, and 7 retired 3-31-2013.

Schedule Page: 403.1 Line No.: 4 Column: d

Cliffside 6 added in 2012. In service date 12/30/2012

Schedule Page: 402.1 Line No.: 20 Column: b

Dan River Steam Total fuel costs reflect Sale of Fly Ash.

Dan River Steam Accounts 0501007, 0501008, and 0501009 for Coal Ash Beneficial Reuse in the amount of $144,516 are excluded.

Schedule Page: 403.1 Line No.: 20 Column: d

Cliffside Steam Total fuel costs include Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Cliffside Steam Plant Units 5 & 6 have been converted to operate using either natural gas, coal or fuel oil. The fuel consumed reflects the dual fuel capacity.

Schedule Page: 403.1 Line No.: 20 Column: e

Riverbend Steam Total fuel costs reflect Sale of Fly Ash.

Riverbend Steam Accounts 0501007, 0501008, 0501009, and 0501015 for Coal Ash Beneficial Reuse in the amount of $938,766 are excluded.

Schedule Page: 402.2 Line No.: -1 Column: c

Buck Combustion Turbine was retired 10/1/2012.

Schedule Page: 403.2 Line No.: -1 Column: d

Buzzard Roost Combustion Turbine was retired 10/1/2012.

Schedule Page: 402.2 Line No.: 3 Column: b

Dates do not reflect units which were retired prior to 1-1-12. Buck 3 and 4 retired 5/15/2011. Buck 5 and 6 retired 3-31-2013.

Schedule Page: 402.2 Line No.: 20 Column: b

Buck Steam Total fuel costs reflect Sale of Fly Ash.

Schedule Page: 402.3 Line No.: -1 Column: c

FOOTNOTE DATA

The Catawba Nuclear Station is a jointly-owned facility with the respondent's share of ownership being 19.246%

Schedule Page: 402.3 Line No.: 5 Column: c

Represents respondent's 19.246% ownership of Catawba units 1 and 2.

Schedule Page: 402.3 Line No.: 9 Column: c

Represents respondent's 19.246% ownership of Catawba units 1 and 2.

Schedule Page: 402.3 Line No.: 10 Column: c

Represents respondent's 19.246% ownership of Catawba units 1 and 2.

Schedule Page: 402.3 Line No.: 11 Column: c

As the operator, average number of employees reflects all employees at the Catawba Nuclear Station.

Schedule Page: 402.3 Line No.: 20 Column: c

Represents respondent's 19.246% ownership of Catawba Units 1 and 2.

Schedule Page: 403.3 Line No.: 20 Column: f

Buck Combined Cycle Total fuels costs include Biogas account 0547106 in the amount of $1,057,296.

Schedule Page: 402.4 Line No.: -1 Column: c

Lee Combined Cycle is a jointly-owned facility with the respondent's share of ownership being 87.265%

Schedule Page: 403.4 Line No.: -1 Column: d

Clemson CHP became a commercial unit on November 22, 2019

Schedule Page: 402.4 Line No.: 5 Column: c

Represents repondent's 87.265% ownership of Lee Combined Cycle.

Schedule Page: 402.4 Line No.: 20 Column: b

Dan River Combined Cycle Total fuels costs include Biogas accounts 0547106, 0547107, and 0547108 in the amount of ($151,816).

Schedule Page: 402.4 Line No.: 20 Column: c

Lee Combined Cycle Total fuel costs represents respondent's ownership share.

Schedule Page: 402 Line No.: 41 Column: b1

Belews Creek Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 41 Column: c1

Marshall Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 41 Column: d1

Allen Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402 Line No.: 43 Column: b1

Belews Creek Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: b2

Belews Creek Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: c1

Marshall Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: c2

Marshall Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: d1

Allen Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: d2

Allen Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: f1

Lee Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 43 Column: f2

Lee Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: b1

Belews Creek Steam Conventional steam heat rates include BTU's of both generation and

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light-off fuels.

Schedule Page: 402 Line No.: 44 Column: b2

Belews Creek Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: c1

Marshall Steam Conventional steam heat rates include BTU's of both generation and light-off fuels.

Schedule Page: 402 Line No.: 44 Column: c2

Marshall Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: d1

Allen Steam Conventional steam heat rates include BTU's of both generation and light-off fuels.

Schedule Page: 402 Line No.: 44 Column: d2

Allen Steam Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: f1

Lee Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402 Line No.: 44 Column: f2

Lee Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 41 Column: d1

Cliffside Steam Average Cost of Fuel per Unit Burned does not include cost for Fuel Handling, Coal Sampling, and Sale of Fly Ash.

Schedule Page: 402.1 Line No.: 43 Column: d1

Cliffside Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 43 Column: d2

Cliffside Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 43 Column: d3

Cliffside Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: d1

Cliffside Steam Conventional steam heat rates include BTU's of both generation and light-off fuels.

Schedule Page: 402.1 Line No.: 44 Column: d2

Cliffside Steam Calculated on all fuels basis only.

Schedule Page: 402.1 Line No.: 44 Column: d3

Cliffside Steam Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: e1

Lincoln Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 43 Column: e2

Lincoln Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: e1

Lincoln Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.2 Line No.: 44 Column: e2

Lincoln Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 38 Column: c1

As the Operator, MBTUs reflects the total MBTUs at the Catawba Nuclear Station.

Schedule Page: 402.3 Line No.: 38 Column: c3

As the Operator, grams of uranium reflects the total grams of uranium at the Catawba Nuclear Station.

Schedule Page: 402.3 Line No.: 43 Column: d1

Mill Creek Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: d2

Mill Creek Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e1

Rockingham Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 43 Column: e2

Rockingham Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d1

FOOTNOTE DATA

Mill Creek Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: d2

Mill Creek Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e1

Rockingham Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.3 Line No.: 44 Column: e2

Rockingham Combustion Turbine Calculated on all fuels basis only.

Schedule Page: 402.4 Line No.: 38 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 39 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 40 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 41 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 42 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 43 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Schedule Page: 402.4 Line No.: 44 Column: c1

Lee Combined Cycle calculated using respondent's ownership share.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2232 Plant Name: Bridgewater (b)	FERC Licensed Project No. 2232 Plant Name: Rhodhiss (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	2011	1925
4	Year Last Unit was Installed	2011	1925
5	Total installed cap (Gen name plate Rating in MW)	27.73	25.50
6	Net Peak Demand on Plant-Megawatts (60 minutes)	33	35
7	Plant Hours Connect to Load	8,551	6,742
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	32	34
10	(b) Under the Most Adverse Oper Conditions	28	33
11	Average Number of Employees	1	3
12	Net Generation, Exclusive of Plant Use - Kwh	82,047,000	95,863,000
13	Cost of Plant		
14	Land and Land Rights	1,715,798	525,914
15	Structures and Improvements	65,245,112	4,771,527
16	Reservoirs, Dams, and Waterways	191,767,747	10,383,139
17	Equipment Costs	35,579,764	19,322,164
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	294,308,421	35,002,744
21	Cost per KW of Installed Capacity (line 20 / 5)	10,613.3581	1,372.6566
22	Production Expenses		
23	Operation Supervision and Engineering	323,359	151,320
24	Water for Power	0	0
25	Hydraulic Expenses	-145,686	-8,986
26	Electric Expenses	139,574	102,143
27	Misc Hydraulic Power Generation Expenses	116,835	137,827
28	Rents	0	0
29	Maintenance Supervision and Engineering	24,643	31,883
30	Maintenance of Structures	5,027	2,588
31	Maintenance of Reservoirs, Dams, and Waterways	89,081	62,326
32	Maintenance of Electric Plant	134,136	86,343
33	Maintenance of Misc Hydraulic Plant	87,256	78,791
34	Total Production Expenses (total 23 thru 33)	774,225	644,235
35	Expenses per net KWh	0.0094	0.0067

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2232 Plant Name: Cowans Ford (b)	FERC Licensed Project No. 2232 Plant Name: Wylie (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1963	1925
4	Year Last Unit was Installed	1967	1925
5	Total installed cap (Gen name plate Rating in MW)	350.00	60.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	236	38
7	Plant Hours Connect to Load	3,167	5,341
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	390	78
10	(b) Under the Most Adverse Oper Conditions	325	72
11	Average Number of Employees	21	7
12	Net Generation, Exclusive of Plant Use - Kwh	263,278,000	77,824,000
13	Cost of Plant		
14	Land and Land Rights	12,390,682	2,707,611
15	Structures and Improvements	18,097,340	7,921,624
16	Reservoirs, Dams, and Waterways	38,023,269	24,973,471
17	Equipment Costs	79,838,485	22,061,389
18	Roads, Railroads, and Bridges	2,240,416	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	150,590,192	57,664,095
21	Cost per KW of Installed Capacity (line 20 / 5)	430.2577	961.0683
22	Production Expenses		
23	Operation Supervision and Engineering	1,899,846	331,490
24	Water for Power	0	0
25	Hydraulic Expenses	-508,829	-176,991
26	Electric Expenses	360,848	120,199
27	Misc Hydraulic Power Generation Expenses	1,283,001	250,687
28	Rents	0	0
29	Maintenance Supervision and Engineering	346,470	79,402
30	Maintenance of Structures	18,237	1,106
31	Maintenance of Reservoirs, Dams, and Waterways	164,992	183,857
32	Maintenance of Electric Plant	320,473	401,605
33	Maintenance of Misc Hydraulic Plant	158,908	47,808
34	Total Production Expenses (total 23 thru 33)	4,043,946	1,239,163
35	Expenses per net KWh	0.0154	0.0159

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2232 Plant Name: Rocky Creek (b)	FERC Licensed Project No. 2232 Plant Name: Cedar Creek (c)
1	Kind of Plant (Run-of-River or Storage)	Run-of-River	Run-of-River
2	Plant Construction type (Conventional or Outdoor)	Conventional	Conventional
3	Year Originally Constructed	1909	1926
4	Year Last Unit was Installed	1909	1926
5	Total installed cap (Gen name plate Rating in MW)	28.00	45.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	48
7	Plant Hours Connect to Load	0	8,595
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	45
10	(b) Under the Most Adverse Oper Conditions	0	43
11	Average Number of Employees	0	2
12	Net Generation, Exclusive of Plant Use - Kwh	0	183,868,000
13	Cost of Plant		
14	Land and Land Rights	0	34,920
15	Structures and Improvements	0	4,026,605
16	Reservoirs, Dams, and Waterways	0	12,017,600
17	Equipment Costs	0	16,304,571
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	32,383,696
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	719.6377
22	Production Expenses		
23	Operation Supervision and Engineering	58,588	161,226
24	Water for Power	0	0
25	Hydraulic Expenses	21,918	5,228
26	Electric Expenses	20,129	157,353
27	Misc Hydraulic Power Generation Expenses	97,341	164,915
28	Rents	0	0
29	Maintenance Supervision and Engineering	23,913	41,223
30	Maintenance of Structures	560	6,015
31	Maintenance of Reservoirs, Dams, and Waterways	-50,256	71,244
32	Maintenance of Electric Plant	20,929	55,873
33	Maintenance of Misc Hydraulic Plant	11,303	41,197
34	Total Production Expenses (total 23 thru 33)	204,425	704,274
35	Expenses per net KWh	0.0000	0.0038

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 2503 Plant Name: Keowee (b)	FERC Licensed Project No. 2686 Plant Name: Thorpe (c)
1	Kind of Plant (Run-of-River or Storage)	Storage	Storage
2	Plant Construction type (Conventional or Outdoor)	Outdoor	Conventional
3	Year Originally Constructed	1971	1941
4	Year Last Unit was Installed	1971	1941
5	Total installed cap (Gen name plate Rating in MW)	157.50	21.60
6	Net Peak Demand on Plant-Megawatts (60 minutes)	153	0
7	Plant Hours Connect to Load	1,159	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	160	23
10	(b) Under the Most Adverse Oper Conditions	152	4
11	Average Number of Employees	10	6
12	Net Generation, Exclusive of Plant Use - Kwh	84,522,000	110,067,000
13	Cost of Plant		
14	Land and Land Rights	21,905,557	1,402,331
15	Structures and Improvements	28,241,265	3,618,406
16	Reservoirs, Dams, and Waterways	17,964,893	5,782,428
17	Equipment Costs	146,956,742	3,817,027
18	Roads, Railroads, and Bridges	0	46,024
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	215,068,457	14,666,216
21	Cost per KW of Installed Capacity (line 20 / 5)	1,365.5140	678.9915
22	Production Expenses		
23	Operation Supervision and Engineering	260,582	168,347
24	Water for Power	0	0
25	Hydraulic Expenses	-253,859	64,180
26	Electric Expenses	1,234,471	8,875
27	Misc Hydraulic Power Generation Expenses	375,656	116,064
28	Rents	0	0
29	Maintenance Supervision and Engineering	37,001	63,409
30	Maintenance of Structures	31,176	10,080
31	Maintenance of Reservoirs, Dams, and Waterways	454,959	130,205
32	Maintenance of Electric Plant	623,530	28,380
33	Maintenance of Misc Hydraulic Plant	442,377	158,728
34	Total Production Expenses (total 23 thru 33)	3,205,893	748,268
35	Expenses per net KWh	0.0379	0.0068

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HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2232 Plant Name: Oxford (d)	FERC Licensed Project No. 2232 Plant Name: Lookout Shoals (e)	FERC Licensed Project No. 2232 Plant Name: Mountain Island (f)	Line No.
Storage	Run-of-River	Storage	1
Conventional	Conventional	Conventional	2
1928	1915	1923	3
1928	1915	1923	4
36.00	25.80	60.00	5
42	29	61	6
6,372	8,727	4,940	7
			8
44	28	62	9
40	28	58	10
3	1	0	11
131,197,000	143,028,000	177,950,000	12
			13
1,247,589	550,590	800,211	14
4,206,347	2,871,615	4,013,230	15
34,895,021	5,580,443	8,434,938	16
22,920,304	13,172,687	19,658,969	17
0	0	0	18
0	0	0	19
63,269,261	22,175,335	32,907,348	20
1,757.4795	859.5091	548.4558	21
			22
228,878	180,059	225,625	23
0	0	0	24
-81,532	24,425	-28,598	25
141,024	141,029	97,167	26
156,851	125,630	224,570	27
0	0	0	28
33,448	24,454	83,654	29
394	4,786	771	30
128,794	81,734	61,080	31
108,103	95,167	206,978	32
82,583	50,170	39,288	33
798,543	727,454	910,535	34
0.0061	0.0051	0.0051	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2232 Plant Name: Fishing Creek (d)	FERC Licensed Project No. 2232 Plant Name: Great Falls (e)	FERC Licensed Project No. 2232 Plant Name: Dearborn (f)	Line No.
Storage	Run-of-River	Run-of-River	1
Conventional	Conventional	Conventional	2
1916	1907	1923	3
1916	1907	1923	4
42.30	24.00	45.50	5
51	0	44	6
6,111	0	8,261	7
			8
56	14	47	9
49	11	42	10
2	5	2	11
182,637,000	-74,000	166,254,000	12
			13
373,568	27,613	0	14
4,381,720	471,318	2,137,143	15
15,831,049	2,869,197	2,369,999	16
27,682,751	6,433,524	16,175,719	17
0	0	633,636	18
0	0	0	19
48,269,088	9,801,652	21,316,497	20
1,141.1132	408.4022	468.4944	21
			22
138,579	77,452	128,046	23
0	0	0	24
34,498	1,394	5,228	25
212,606	8,612	116,783	26
148,667	200,584	193,316	27
0	0	0	28
38,975	12,467	39,106	29
45,910	9,915	1,251	30
53,915	52,334	71,679	31
291,224	14,938	166,790	32
65,116	25,010	12,043	33
1,029,490	402,706	734,242	34
0.0056	0.0000	0.0044	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2232 Plant Name: Wateree (d)	FERC Licensed Project No. 2331 Plant Name: Ninety-Nine Islands (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage	Run-of-River		1
Conventional	Conventional		2
1919	1910		3
1919	1910		4
76.70	18.00	0.00	5
90	15	0	6
8,734	5,296	0	7
			8
90	20	0	9
85	10	0	10
2	1	0	11
319,360,000	67,604,000	0	12
			13
627,443	151,343	0	14
10,079,882	1,219,451	0	15
14,861,723	12,845,342	0	16
29,970,498	11,842,049	0	17
0	0	0	18
0	0	0	19
55,539,546	26,058,185	0	20
724.1140	1,447.6769	0.0000	21
			22
758,436	225,077	0	23
0	0	0	24
46,214	18,349	0	25
172,525	86,601	0	26
267,853	189,064	0	27
0	0	0	28
52,943	10,856	0	29
22,450	1,149	0	30
112,827	62,793	0	31
159,964	194,701	0	32
272,522	449,574	0	33
1,865,734	1,238,164	0	34
0.0058	0.0183	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 2692 Plant Name: Nantahala (d)	FERC Licensed Project No. 2698 Plant Name: Tennessee Creek (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
Storage	Storage		1
Conventional	Conventional		2
1942	1955		3
1942	1955		4
43.20	10.80	0.00	5
0	0	0	6
0	0	0	7
			8
51	11	0	9
37	7	0	10
2	0	0	11
236,212,000	15,934,000	0	12
			13
469,013	475,718	0	14
2,561,850	355,878	0	15
13,614,636	12,563,104	0	16
6,956,488	3,103,911	0	17
239,971	72,590	0	18
0	0	0	19
23,841,958	16,571,201	0	20
551.8972	1,534.3705	0.0000	21
			22
321,870	68,678	0	23
0	0	0	24
34,184	0	0	25
67,558	4,425	0	26
248,692	45,168	0	27
0	0	0	28
116,746	4,348	0	29
59,987	507	0	30
215,124	40,575	0	31
317,113	9,092	0	32
61,418	53,760	0	33
1,442,692	226,553	0	34
0.0061	0.0142	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

FOOTNOTE DATA

Schedule Page: 406 Line No.: 9 Column: b

Capability applicable to individual plant only; system capability cannot be derived from this data as system capability assumes limited water resources which is not reflected in this amount. Also, capability of small hydroelectric plants is excluded from these pages.

Schedule Page: 406 Line No.: 9 Column: c

Capability applicable to individual plant only; system capability cannot be derived from this data as system capability assumes limited water resources which is not reflected in this amount. Also, capability of small hydroelectric plants is excluded from these pages.

Schedule Page: 406 Line No.: 9 Column: d

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Schedule Page: 406 Line No.: 9 Column: e

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Schedule Page: 406.1 Line No.: 10 Column: f

Capability applicable to individual plant only; system capability cannot be derived from this data because capability of small hydroelectric plants is excluded from these pages.

Schedule Page: 406.1 Line No.: 11 Column: e

Remote control operation.

Schedule Page: 406.2 Line No.: 9 Column: b

Capability applicable to individual plant only; system capability cannot be derived from this data as system capability assumes limited water resources which is not reflected in this amount. Also, capability of small hydroelectric plants is excluded from these pages.

Schedule Page: 406.2 Line No.: 9 Column: c

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FOOTNOTE DATA

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Remote control operation.

Schedule Page: 406.3 Line No.: 11 Column: e

Remote control operation.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 2503 Plant Name: Jocassee (b)
1	Type of Plant Construction (Conventional or Outdoor)	Conventional
2	Year Originally Constructed	1973
3	Year Last Unit was Installed	1975
4	Total installed cap (Gen name plate Rating in MW)	710
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	783
6	Plant Hours Connect to Load While Generating	2,781
7	Net Plant Capability (in megawatts)	780
8	Average Number of Employees	19
9	Generation, Exclusive of Plant Use - Kwh	1,108,521,000
10	Energy Used for Pumping	1,251,128,000
11	Net Output for Load (line 9 - line 10) - Kwh	-1,393,735,000
12	Cost of Plant	
13	Land and Land Rights	5,273,013
14	Structures and Improvements	28,086,977
15	Reservoirs, Dams, and Waterways	54,627,851
16	Water Wheels, Turbines, and Generators	70,794,015
17	Accessory Electric Equipment	14,787,853
18	Miscellaneous Powerplant Equipment	4,383,447
19	Roads, Railroads, and Bridges	415,508
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	178,368,664
22	Cost per KW of installed cap (line 21 / 4)	251.2235
23	Production Expenses	
24	Operation Supervision and Engineering	876,844
25	Water for Power	
26	Pumped Storage Expenses	46,395
27	Electric Expenses	804,504
28	Misc Pumped Storage Power generation Expenses	1,970,010
29	Rents	
30	Maintenance Supervision and Engineering	535,169
31	Maintenance of Structures	182,973
32	Maintenance of Reservoirs, Dams, and Waterways	265,926
33	Maintenance of Electric Plant	1,144,732
34	Maintenance of Misc Pumped Storage Plant	497,645
35	Production Exp Before Pumping Exp (24 thru 34)	6,324,198
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	6,324,198
38	Expenses per KWh (line 37 / 9)	0.0057

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 2740 Plant Name: Bad Creek (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
Outdoor			1
1991			2
1991			3
1,065			4
1,424			5
2,988			6
1,360			7
35			8
2,073,886,000			9
2,644,799,000			10
-570,913,000			11
			12
1,145,342			13
233,322,370			14
455,702,848			15
238,112,498			16
57,564,794			17
29,893,694			18
17,869,699			19
			20
1,033,611,245			21
970.5270			22
			23
1,455,194			24
			25
2,222			26
1,227,081			27
2,530,717			28
			29
839,282			30
163,046			31
417,330			32
1,190,654			33
1,066,899			34
8,892,425			35
			36
8,892,425			37
0.0043			38

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1	HYDRO PLANTS:					
2	Bear Creek - Project 2698	1954	9.00	10.0	21,408,000	15,187,113
3	Cedar Cliff - Project 2698	1952	6.40	7.0	24,460,000	9,881,569
4	Queen's Creek - Project 2694	1949	1.40	2.0	5,847,000	1,323,533
5	Tuckasegee - Project 2686	1950	3.00	3.0	8,306,000	4,185,173
6						
7						
8						
9						
10						
11						
12						
13						
14						
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Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses		Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
		Fuel (i)	Maintenance (j)			
						1
1,687,457	98,421		148,452			2
1,543,995	84,997		93,802			3
945,381	29,291		90,648			4
1,395,058	112,387		102,093			5
						6
						7
						8
						9
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FOOTNOTE DATA

Schedule Page: 410 Line No.: 1 Column: a

Refer to Important Changes During The Year, page 108.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Antioch Tie	Appalachian Power	525.00	525.00	Tower	27.89		1
2	Cliffside Steam Sta #6	McGuire SW	525.00	525.00	Tower	48.70		1
3	Cliffside Stm	Cliffside SW	525.00	525.00	Tower & Pole	1.14		1
4	Jocassee Tie	Bad Creek HYD	525.00	525.00	Tower	9.27		1
5	Jocassee Tie	Cliffside Tie	525.00	525.00	Tower	70.57		1
6	McGuire SW	Antioch Tie	525.00	525.00	Tower	54.83		1
7	MCGuire SW	Woodleaf Switching	525.00	525.00	Tower	29.96		1
8	Newport Tie	Progress Energy Rockingham	525.00	525.00	Tower	48.33		1
9	Newport Tie	McGuire Switching	525.00	525.00	Tower & Pole	32.43		1
10	Oconee Nuclear	Newport Tie	525.00	525.00	Tower	107.47		1
11	Oconee Nuclear	South Hall	525.00	525.00	Tower & Pole	22.46		1
12	Oconee Nuclear	Jocassee Tie	525.00	525.00	Tower	20.89		1
13	Pleasant Garden Tie	Parkwood Tie	525.00	525.00	Tower	49.29		1
14	Woodleaf Switching	Pleasant Garden Tie	525.00	525.00	Tower	52.75		1
15								
16	TOTAL 525 KV LINES					575.98		14
17								
18	Allen Steam	Catawba Nuclear	230.00	230.00	Tower	10.91		2
19	Allen Steam	Riverbend Steam	230.00	230.00	Tower	12.58		2
20	Allen Steam	Winecoff Tie	230.00	230.00	Tower	32.17		2
21	Allen Steam	Woodlawn Tie	230.00	230.00	Tower & Pole	8.40		2
22	Anderson Tie	Hodges Tie	230.00	230.00	Tower	25.73		2
23	Antioch Tie	Wilkes Tie	230.00	230.00	Tower	4.26		2
24	Beckerdite Tie	Belews Creek Steam	230.00	230.00	Tower	24.67		2
25	Beckerdite Tie	Pleasant Garden Tie	230.00	230.00	Tower	28.22		2
26	Belews Creek Steam	Ernest Switching Station	230.00	230.00	Tower	13.61		2
27	Belews Creek Steam	North Greensboro Tie	230.00	230.00	Tower	21.58		2
28	Belews Creek Steam	Pleasant Garden Tie	230.00	230.00	Tower & Pole	38.76		2
29	Belews Creek Steam	Rural Hall Tie	230.00	230.00	Tower	18.28		2
30	Bobwhite Switching	North Greensboro Tie	230.00	230.00	Tower	3.87		2
31	Buck Tie	Beckerdite Tie	230.00	230.00	Tower	23.76		2
32	Catawba Nuclear	Newport Tie	230.00	230.00	Tower & Pole	10.38		4
33	Catawba Nuclear	Pacolet Tie	230.00	230.00	Tower	41.01		2
34	Catawba Nuclear	Peacock Tie	230.00	230.00	Tower	14.87		2
35	Catawba Nuclear	Ripp Switching Station	230.00	230.00	Tower	24.33		2
36					TOTAL	8,238.08	43.89	2,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	On Structures of Another Line (g)	Number Of Circuits (h)
1	Central Tie	Anderson Tie	230.00	230.00	Tower	23.21		2
2	Cliffside Steam	Pacolet Tie	230.00	230.00	Tower	23.19		2
3	Cliffside Steam	Shelby Tie	230.00	230.00	Tower	14.09		2
4	Cowans Ford Hydro	McGuire Switching	230.00	230.00	Tower	1.68		2
5	East Durham Tie	Parkwood Tie	230.00	230.00	Tower	19.31		2
6	Eno Tap Bent	Progress Energy (Roxboro)	230.00	230.00	Tower	13.86		2
7	Eno Tap Bent	East Durham Tie	230.00	230.00	Tower	15.76		2
8	Ernest Switching Station	Sadler Tie	230.00	230.00	Tower	12.54		2
9	Harrisburg Tie	Oakboro Tie	230.00	230.00	Tower	21.39		2
10	Hartwell Hydro	Anderson Tie	230.00	230.00	Tower	11.12		2
11	Jocassee Switching	Shiloh Switching	230.00	230.00	Tower	22.33		2
12	Jocassee Switching	Tuckasegee Tie	230.00	230.00	Tower	26.71		2
13	Lakewood Tie	Riverbend Steam	230.00	230.00	Tower	10.64		2
14	Lincoln CT	Longview Tie	230.00	230.00	Tower	30.96		2
15	Longview Tie	McDowell Tie	230.00	230.00	Tower	31.69		2
16	Marshall Steam	Beckerdite Tie	230.00	230.00	Tower	52.47		2
17	Marshall Steam	Longview Tie	230.00	230.00	Tower	28.91		2
18	Marshall Steam	McGuire Switching	230.00	230.00	Tower	13.84		2
19	Marshall Steam	Stamey Tie	230.00	230.00	Tower	13.55		2
20	Marshall Steam	Winecoff Tie	230.00	230.00	Tower	24.28		2
21	McGuire Switching	Harrisburg Tie	230.00	230.00	Tower	36.20		4
22	Mitchell River Tie	Antioch Tie	230.00	230.00	Tower & Pole	16.82		2
23	Mitchell River Tie	Rural Hall Tie	230.00	230.00	Tower	26.61		2
24	Morningstar Tie	Oakboro Tie	230.00	230.00	Tower	32.50		1
25	North Greenville Tie	Central Tie	230.00	230.00	Tower & Pole	26.57		2
26	North Greenville Tie	Shiloh Switching	230.00	230.00	Tower	8.99		2
27	Newport Tie	Morningstar Tie	230.00	230.00	Tower & Pole	33.47		1
28	Newport Tie	SCE&G (Parr)	230.00	230.00	Tower	45.63		1
29	Oakboro Tie	Progress Energy Rockingham	230.00	230.00	Tower	5.14		1
30	Oconee Nuclear	Central Tie	230.00	230.00	Tower	17.62		4
31	Oconee Nuclear	Jocassee Switching	230.00	230.00	Tower & Pole	12.36		2
32	Oconee Nuclear	North Greenville Tie	230.00	230.00	Tower & Pole	29.09		2
33	Pacolet Tie	Tiger Tie	230.00	230.00	Tower	27.86		2
34	Peach Valley Tie	Tiger Tie	230.00	230.00	Tower	15.59		2
35	Pisgah Tie	Progress Energy Skyland Stm	230.00	230.00	Tower	14.48		2
36					TOTAL	8,238.08	43.89	2,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION From (a)	DESIGNATION To (b)	VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase) Operating (c)	VOLTAGE (KV) Designed (d)	Type of Supporting Structure (e)	LENGTH (Pole miles) (In the case of underground lines report circuit miles) On Structure of Line Designated (f)	LENGTH On Structures of Another Line (g)	Number Of Circuits (h)
1	Pleasant GardenTie	Eno Tie	230.00	230.00	Tower	42.52		2
2	Ripp Switching	Riverview Switching	230.00	230.00	Tower	9.72		2
3	Ripp Switching	Shelby Tie	230.00	230.00	Tower	9.97		2
4	Riverbend Steam	Lincoln CT	230.00	230.00	Tower & Pole	11.54		2
5	Riverbend Steam	McGuire Switching	230.00	230.00	Tower	5.62		2
6	Riverbend Steam	Ripp Switching	230.00	230.00	Tower	30.06		2
7	Riverview Switching	Peach Valley Tie	230.00	230.00	Tower	19.20		2
8	SCE&G (Parr)	Bush River Tie	230.00	230.00	Tower	17.74		1
9	Shady Grove Tap	Shady Grove Tie	230.00	230.00	Tower	7.79		2
10	Shiloh Switching	Pisgah Tie	230.00	230.00	Tower	21.96		2
11	Shiloh Switching	Tiger Tie	230.00	230.00	Tower	21.31		2
12	Stamey Tie	Mitchell River Tie	230.00	230.00	Tower	36.15		2
13	Tiger Tie	North Greenville Tie	230.00	230.00	Tower	18.30		2
14	Winecoff Tie	Buck Tie	230.00	230.00	Tower	24.09		2
15								
16	TOTAL 230 KV LINES					1,393.82		135
17								
18	Fontana (TVA)	Nantahala Hydro	161.00	161.00	Tower	18.48		1
19	Nantahala Hydro	Webster Tie	161.00	161.00	Tower	12.63	12.99	1
20	Nantahala Hydro	Marble Tie	161.00	161.00	Pole	16.80		2
21	Nantahala Hydro	Robbinsville Substation	161.00	161.00	Tower	0.03	8.12	1
22	Santeetlah	Robbinsville Substation	161.00	161.00	Tower	0.44	10.23	1
23	Tuckasegee Tie	Thorpe Hydro	161.00	161.00	Tower & Pole	3.17		1
24	Tuckasegee Tie	Wests Mill Tie	161.00	161.00	Tower	10.44	12.55	1
25	Webster Tie	Lake Emory Tie	161.00	161.00	Pole	12.71		1
26	Wests Mill Tie	Lake Emory Tie	161.00	161.00	Pole	6.71		1
27	Wests Mill Tie	Nantahala Hydro	161.00	161.00	Tower	12.98		1
28	Wests Mill Tie	Swain Tie	161.00	161.00	Tower & Pole	12.34		1
29								
30	TOTAL 161 KV LINES					106.73	43.89	12
31								
32	Dan River Steam	Appalachian Power (Fieldale	138.00	138.00	Tower & Pole	6.50		1
33	115 KV Lines		115.00	115.00	Tower & Pole	54.91		5
34	100 KV Lines		100.00	100.00	Tower	717.33		246
35	100 KV Lines		100.00	100.00	Pole	189.91		249
36					TOTAL	8,238.08	43.89	2,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting Structure	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of Circuits
	From (a)	To (b)	Operating (c)	Designed (d)	(e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	(h)
1	100 KV Lines		100.00	100.00	Underground	10.04		7
2	100 kV Lines		100.00		Tower & Pole	2,655.70		404
3	138 kV Lines		138.00	138.00	Tower & Pole	6.51		
4	TOTAL 100 - 138 KV LINES					3,640.90		912
5								
6	66 KV Lines		66.00	66.00	Pole	88.17		25
7	66 KV Lines		66.00	66.00	Tower & Pole	17.43		3
8								
9	TOTAL 66 KV LINES					105.60		28
10								
11	44 KV Lines		44.00	44.00	Tower	0.12		8
12	44 KV Lines		44.00	44.00	Pole	1,339.48		1,038
13	44 KV Lines		44.00	44.00	Underground	7.21		15
14	44 kV Lines		44.00	44.00	Tower & Pole	972.61		193
15	TOTAL 44 KV LINES					2,319.42		1,254
16								
17	33 KV Lines		33.00	33.00	Tower & Pole	16.02		4
18	24 KV Lines		24.00	24.00	Tower & Pole	53.95		35
19	24 KV Lines		24.00	24.00	Underground	0.95		2
20	4 to 12 KV Lines		12.00	12.00	Tower & Pole	24.47		52
21	4 to 12 KV Lines		12.00	12.00	Underground	0.24		2
22								
23	TOTAL 4-33 KV LINES					95.63		95
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	8,238.08	43.89	2,450

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
2515								1
2515								2
2515								3
2515								4
2515								5
2515								6
2515								7
2515								8
2515								9
2515								10
2515								11
2515								12
2515								13
2515								14
	20,656,136	112,037,555	132,693,691					15
	20,656,136	112,037,555	132,693,691					16
								17
1272								18
1272								19
954 & 1272								20
2156								21
954								22
954								23
2156								24
954								25
1272								26
2156								27
2156								28
2156								29
2156								30
954								31
1272								32
954								33
1272								34
1272								35
	179,858,736	2,066,109,901	2,245,968,637	1,112,296	18,572,047		19,684,343	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
954								2
954								3
795								4
1272								5
1272								6
1272								7
1272								8
954								9
954								10
2156								11
1272								12
954								13
795								14
954								15
954								16
1272								17
1272								18
954								19
1272								20
1272								21
954								22
954								23
954								24
954								25
954								26
954								27
954								28
954								29
1272								30
2156								31
1272								32
954								33
795								34
954								35
	179,858,736	2,066,109,901	2,245,968,637	1,112,296	18,572,047		19,684,343	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
954								1
795								2
954								3
795								4
1272								5
795								6
795								7
954								8
2515								9
954								10
1272								11
954								12
954								13
954								14
	41,393,709	332,065,258	373,458,967					15
	41,393,709	332,065,258	373,458,967					16
								17
795								18
795								19
795								20
795								21
795								22
397.5								23
795								24
636								25
795								26
795								27
954								28
	3,736,539	114,445,369	118,181,908					29
	3,736,539	114,445,369	118,181,908					30
								31
477								32
		257,520	257,520					33
								34
								35
	179,858,736	2,066,109,901	2,245,968,637	1,112,296	18,572,047		19,684,343	36

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
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9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
								1
	77,927,231	998,865,353	1,076,792,584					2
								3
	77,927,231	999,122,873	1,077,050,104					4
								5
								6
								7
	5,793,848	43,095,295	48,889,143					8
	5,793,848	43,095,295	48,889,143					9
								10
								11
								12
								13
	29,600,021	457,335,623	486,935,644					14
	29,600,021	457,335,623	486,935,644					15
								16
								17
								18
								19
								20
								21
	751,252	8,007,928	8,759,180					22
	751,252	8,007,928	8,759,180					23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
				1,112,296	18,572,047		19,684,343	35
	179,858,736	2,066,109,901	2,245,968,637	1,112,296	18,572,047		19,684,343	36

FOOTNOTE DATA

Schedule Page: 422 Line No.: 1 Column: h

For column (h) the number of circuits - 1 & 2

Schedule Page: 422 Line No.: 1 Column: i

All Conductors in column (i) are ACSR shown in MCM.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	CHERRYVILLE T	BUFFALO CREEK RET	7.75	Towers & Poles	0.04		
2	PROFILE PRODUCTS TAP		0.08	Poles	37.50		
3	HERMAN RD RET TAP		0.18	Poles	16.70		
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		8.01		54.24		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
336/556	ACSR		100		1,823,074	261,082	96,222	2,180,378	1
556	ACSR					114,560		114,560	2
556	ACSR				185,566	244,054		429,620	3
									4
									5
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					2,008,640	619,696	96,222	2,724,558	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ABBOTTS CREEK TIE LEXINGTON NC	TRANS	100.00	44.00	
2	ABBOTTS CREEK TIE LEXINGTON NC	TRANS	100.00	44.00	
3	ABBOTTS CREEK TIE LEXINGTON NC	TRANS	100.00	44.00	
4	ABBOTTS CREEK TIE LEXINGTON NC	TRANS	24.00	0.20	
5	ACREROCK TIE DALLAS NC	TRANS	44.00	6.90	2.40
6	ACREROCK TIE DALLAS NC	TRANS	44.00	6.90	2.40
7	ACREROCK TIE DALLAS NC	TRANS	44.00	6.90	2.40
8	ACREROCK TIE DALLAS NC	TRANS	44.00	6.90	2.40
9	ACREROCK TIE DALLAS NC	TRANS	100.00	44.00	
10	ACREROCK TIE DALLAS NC	TRANS	100.00	44.00	
11	ADVANCE RET ADVANCE NC	DIST	100.00	13.00	
12	ADVANCE RET ADVANCE NC	DIST	100.00	13.00	
13	ALBEMARLE CITY DEL 2 ALBEMARLE NC	DIST	100.00	24.00	
14	ALBEMARLE CITY DEL 2 ALBEMARLE NC	DIST	100.00	24.00	13.00
15	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
16	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
17	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
18	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
19	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
20	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
21	ALBEMARLE SW STA ALBEMARLE NC	DIST	100.00	13.00	6.90
22	ALLEN STEAM PL BELMONT NC	TRANS	230.00	100.00	13.00
23	ALLEN STEAM PL BELMONT NC	TRANS	100.00	24.00	
24	ALLEN STEAM PL BELMONT NC	TRANS	100.00	24.00	
25	ALLEN STEAM PL BELMONT NC	TRANS	230.00	100.00	44.00
26	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
27	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
28	ALLEN STEAM PL BELMONT NC	TRANS	100.00	13.00	
29	ALLEN STEAM PL BELMONT NC	TRANS	100.00	15.00	15.00
30	ALLEN STEAM PL BELMONT NC	TRANS	230.00	13.00	
31	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
32	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
33	ANDERSON TIE STARR SC	TRANS	230.00	44.00	
34	ANDERSON TIE STARR SC	TRANS	230.00	100.00	44.00
35	ANDERSON TIE STARR SC	TRANS	44.00	2.40	0.60
36	ANDERSON TIE STARR SC	TRANS	44.00	2.40	0.60
37	ANDERSON TIE STARR SC	TRANS	44.00	2.40	0.60
38	ANDERSON TIE STARR SC	TRANS	44.00		
39	ANDERSON TIE STARR SC	TRANS	44.00	0.40	
40	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
2	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
3	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
4	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
5	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
6	ANTIOCH TIE WILKESBORO NC	TRANS	525.00	230.00	22.90
7	ANTIOCH TIE WILKESBORO NC	TRANS	22.90	0.40	
8	ANTIOCH TIE WILKESBORO NC	TRANS	22.90	0.40	
9	APALACHE RET GREER SC	DIST	44.00	13.00	
10	APALACHE RET GREER SC	DIST	44.00	13.00	
11	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
12	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
13	ARROWOOD RET CHARLOTTE NC	DIST	100.00	24.00	
14	ASHCRAFT AVE RET MONROE NC	DIST	100.00	24.00	
15	ASHE ST SW STA DURHAM NC	TRANS	100.00	13.00	
16	ASHE ST SW STA DURHAM NC	TRANS	100.00	13.00	
17	ASHEVILLE HWY RET HENDERSONVILLE NC	DIST	100.00	13.00	
18	ASHEVILLE HWY RET HENDERSONVILLE NC	DIST	100.00	13.00	
19	ASHEVILLE HWY RET HENDERSONVILLE NC	DIST	100.00	13.00	
20	AUGUSTA RD RET GREENVILLE SC	DIST	100.00	13.00	
21	AUGUSTA RD RET GREENVILLE SC	DIST	100.00	13.00	
22	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
23	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
24	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
25	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
26	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
27	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
28	AVONDALE RET AVONDALE NC	DIST	44.00	6.90	2.40
29	BAD CREEK HYDRO BAD CREEK SC	TRANS	500.00	24.00	24.00
30	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	24.00	
31	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	24.00	
32	BAD CREEK HYDRO BAD CREEK SC	TRANS	525.00	24.00	
33	BAD CREEK HYDRO BAD CREEK SC	TRANS	100.00	4.10	
34	BAINBRIDGE RET GREENVILLE SC	DIST	100.00	13.00	
35	BAINBRIDGE RET GREENVILLE SC	DIST	100.00	13.00	
36	BALL PARK RET KANNAPOLIS NC	DIST	44.00	2.40	
37	BALL PARK RET KANNAPOLIS NC	DIST	44.00	2.40	
38	BALL PARK RET KANNAPOLIS NC	DIST	44.00	2.40	
39	BALL PARK RET KANNAPOLIS NC	DIST	44.00	2.40	
40	BALL PARK RET KANNAPOLIS NC	DIST	44.00	6.90	2.40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BALL PARK RET KANNAPOLIS NC	DIST	44.00	6.90	2.40
2	BALL PARK RET KANNAPOLIS NC	DIST	44.00	6.90	2.40
3	BALL PARK RET KANNAPOLIS NC	DIST	44.00	6.90	2.40
4	BALSAM RET HENDERSONVILLE NC	DIST	44.00	13.00	6.90
5	BALSAM RET HENDERSONVILLE NC	DIST	44.00	13.00	6.90
6	BALSAM RET HENDERSONVILLE NC	DIST	44.00	13.00	6.90
7	BALSAM RET HENDERSONVILLE NC	DIST	44.00	13.00	
8	BANCROFT RET CHARLOTTE NC	DIST	100.00	13.00	
9	BANCROFT RET CHARLOTTE NC	DIST	100.00	13.00	
10	BANKS ST RET FORT MILL SC	DIST	100.00	13.00	
11	BANNERTOWN TIE MT AIRY NC	TRANS	100.00	13.00	
12	BANNERTOWN TIE MT AIRY NC	TRANS	100.00	13.00	
13	BANNERTOWN TIE MT AIRY NC	TRANS	100.00	13.00	
14	BAPTIST HOSP T&D WINSTON-SALEM NC	DIST	100.00	13.00	
15	BAPTIST HOSP T&D WINSTON-SALEM NC	DIST	100.00	13.00	
16	BARBEE CHAPEL RD RET DURHAM NC	DIST	100.00	24.00	
17	BARRIER RD RET RIMER NC	DIST	100.00	13.00	
18	BEATTIES FORD RET CHARLOTTE NC	DIST	100.00	24.00	
19	BEATTIES FORD RET CHARLOTTE NC	DIST	100.00	13.00	
20	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
21	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
22	BEAVER DAM RET MARSHVILLE NC	DIST	100.00	24.00	
23	BECKERDITE SVC WINSTON-SALEM NC	TRANS	16.00		
24	BECKERDITE SVC WINSTON-SALEM NC	TRANS	100.00	24.00	
25	BECKERDITE SVC WINSTON-SALEM NC	TRANS	100.00	24.00	
26	BECKERDITE SVC WINSTON-SALEM NC	TRANS	100.00	24.00	
27	BECKERDITE SVC WINSTON-SALEM NC	TRANS	100.00	24.00	
28	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	44.00
29	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	13.00
30	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	13.00
31	BECKERDITE TIE WINSTON-SALEM NC	TRANS	230.00	100.00	44.00
32	BECKERDITE TIE WINSTON-SALEM NC	TRANS	100.00	13.00	6.90
33	BECKERDITE TIE WINSTON-SALEM NC	TRANS	100.00	13.00	6.90
34	BECKERDITE TIE WINSTON-SALEM NC	TRANS	100.00	13.00	6.90
35	BECKERDITE TIE WINSTON-SALEM NC	TRANS	100.00	13.00	6.90
36	BECKERDITE TIE WINSTON-SALEM NC	TRANS	44.00	0.40	
37	BECKERDITE TIE WINSTON-SALEM NC	TRANS	44.00	0.40	
38	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
39	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
40	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BEECH ST RET HENDERSONVILLE NC	DIST	44.00	2.40	
2	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	230.00	13.00	
3	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	230.00	13.00	
4	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
5	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
6	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
7	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
8	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
9	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
10	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
11	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
12	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
13	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
14	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	13.00	6.90	6.90
15	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	230.00	6.90	6.90
16	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
17	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
18	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
19	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
20	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
21	BELEWS CREEK STEAM STA UNIT 1 BELEWS CREEK NC	TRANS	6.90	0.60	
22	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	13.00	
23	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	24.00	
24	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
25	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
26	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
27	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
28	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
29	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
30	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
31	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
32	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
33	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
34	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	13.00	6.90	6.90
35	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	230.00	6.90	6.90
36	BELEWS CREEK STEAM STA UNIT 2 BELEWS CREEK NC	TRANS	6.90	0.60	
37	BELEWS CREEK SW STA BELEWS CREEK NC	TRANS	6.90	0.40	
38	BELEWS CREEK SW STA BELEWS CREEK NC	TRANS	230.00	18.00	
39	BELLHAVEN RET CHARLOTTE NC	DIST	100.00	13.00	
40	BELLHAVEN RET CHARLOTTE NC	DIST	100.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BELMONT TIE BELMONT NC	TRANS	100.00	44.00	
2	BELMONT TIE BELMONT NC	TRANS	100.00	44.00	
3	BELMONT TIE BELMONT NC	TRANS	44.00	13.00	
4	BELMONT TIE BELMONT NC	TRANS	44.00	13.00	
5	BELMONT TIE BELMONT NC	TRANS	24.00	0.20	
6	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
7	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
8	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
9	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
10	BELTON RET BELTON SC	DIST	24.00	2.40	
11	BELTON RET BELTON SC	DIST	24.00	2.40	0.60
12	BELTON RET BELTON SC	DIST	24.00	2.40	0.60
13	BELTON RET BELTON SC	DIST	24.00	2.40	0.60
14	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
15	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
16	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
17	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
18	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
19	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
20	BELTON RET BELTON SC	DIST	44.00	6.90	2.40
21	BELTON TIE BELTON SC	TRANS	100.00	44.00	
22	BELTON TIE BELTON SC	TRANS	100.00	44.00	
23	BELTON TIE BELTON SC	TRANS	100.00	44.00	
24	BELTON TIE BELTON SC	TRANS	24.00	0.20	
25	BEREA RD RET GREENVILLE SC	DIST	100.00	13.00	
26	BEREA RD RET GREENVILLE SC	DIST	100.00	13.00	
27	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	2.40	
28	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	2.40	
29	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	2.40	
30	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
31	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
32	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
33	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
34	BESSEMER CITY RET BESSEMER CITY NC	DIST	44.00	6.90	2.40
35	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
36	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
37	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
38	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
39	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
40	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BETHEL RET CLOVER SC	DIST	44.00	6.90	2.40
2	BETHLEHEM SS HICKORY NC	DIST	44.00	13.00	
3	BETHLEHEM SS HICKORY NC	DIST	44.00	13.00	
4	BETHWARE RET KINGS MOUNTAIN NC	DIST	100.00	13.00	
5	BIG WILLOW RET HENDERSONVILLE NC	DIST	44.00	13.00	
6	BINGHAM RET HILLSBOROUGH NC	DIST	100.00	13.00	
7	BINGHAM RET HILLSBOROUGH NC	DIST	100.00	13.00	
8	BLACK CREEK RET CHESTER SC	DIST	100.00	13.00	
9	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
10	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
11	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
12	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	6.90	
13	BLACKSBURG RET BLACKSBURG SC	DIST	44.00	13.00	
14	BLACKSBURG TIE BLACKSBURG SC	TRANS	100.00	44.00	
15	BLACKSBURG TIE BLACKSBURG SC	TRANS	100.00	44.00	
16	BLACKSBURG TIE BLACKSBURG SC	TRANS	24.00	0.20	
17	BLAKLEY RET LAURENS SC	DIST	44.00	13.00	
18	BLANTON RET SHELBY NC	DIST	44.00	13.00	
19	BLANTON RET SHELBY NC	DIST	44.00	13.00	
20	BLANTYRE RET HORSE SHOE NC	DIST	100.00	13.00	
21	BLUE RIDGE E C DEL 11 EASLEY SC	DIST	100.00	13.00	
22	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
23	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
24	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
25	BLUE RIDGE E C DEL 12 WESTMINSTER SC	DIST	100.00	6.90	
26	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
27	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
28	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
29	BLUE RIDGE E C DEL 14 PICKENS SC	DIST	100.00	6.90	2.40
30	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
31	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
32	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	2.40	
33	BOB JONES UNIV DIST GREENVILLE SC	DIST	13.00	4.10	
34	BOILING SPRINGS RET BOILING SPRINGS SC	DIST	100.00	13.00	
35	BOILING SPRINGS RET BOILING SPRINGS SC	DIST	100.00	13.00	
36	BOND PARK RET SPARTANBURG SC	DIST	44.00	13.00	
37	BOND PARK RET SPARTANBURG SC	DIST	44.00	24.00	13.00
38	BOND PARK RET SPARTANBURG SC	DIST	44.00	13.00	4.10
39	BOUNTY LAND SS SENECA SC	DIST	44.00	6.90	2.40
40	BOUNTY LAND SS SENECA SC	DIST	44.00	13.00	6.90

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BOUNTY LAND SS SENECA SC	DIST	44.00	24.00	13.00
2	BOUNTY LAND SS SENECA SC	DIST	44.00	6.90	2.40
3	BOUNTY LAND SS SENECA SC	DIST	44.00	13.00	
4	BRANCH RD RET WALHALLA SC	DIST	44.00	13.00	
5	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
6	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
7	BRANCH RD RET WALHALLA SC	DIST	44.00	6.90	2.40
8	BRANTLEY RD RET KANNAPOLIS NC	DIST	100.00	13.00	
9	BRANTLEY RD RET KANNAPOLIS NC	DIST	100.00	13.00	
10	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
11	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
12	BRASSFIELD RET DURHAM NC	DIST	230.00	24.00	
13	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	13.00	
14	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	13.00	
15	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	24.00	
16	BRAWLEY SCHOOL RET MOORESVILLE NC	DIST	100.00	24.00	
17	BRENTWOOD RET SIMPSONVILLE SC	DIST	100.00	13.00	
18	BRENTWOOD RET SIMPSONVILLE SC	DIST	100.00	13.00	
19	BRENTWOOD RET SIMPSONVILLE SC	DIST	100.00	13.00	
20	BREVARD RET BREVARD NC	DIST	44.00	2.40	
21	BREVARD RET BREVARD NC	DIST	44.00	2.40	
22	BREVARD RET BREVARD NC	DIST	44.00	2.40	
23	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
24	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
25	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
26	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
27	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
28	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
29	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
30	BREVARD RET BREVARD NC	DIST	44.00	6.90	2.40
31	BRIAR CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
32	BRIAR CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
33	BRIDGEPORT RET MORGANTON NC	DIST	44.00	13.00	
34	BRIDGEPORT RET MORGANTON NC	DIST	44.00	13.00	
35	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	6.90	
36	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	6.90	
37	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	100.00	44.00	
38	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	
39	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	
40	BRIDGEWATER HYDRO PL MORGANTON NC	TRANS	6.90	0.60	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BROOK ST RET NORTH WILKESBORO NC	DIST	100.00	13.00	
2	BROOK ST RET NORTH WILKESBORO NC	DIST	100.00	13.00	
3	BROOKWOOD RET WINSTON-SALEM NC	DIST	100.00	13.00	
4	BROOKWOOD RET WINSTON-SALEM NC	DIST	100.00	13.00	
5	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	
6	BROUGHTON RET MORGANTON NC	DIST	44.00	13.00	
7	BROWNS FORD RET NORTH WILKESBORO NC	DIST	100.00	13.00	
8	BROWNS FORD RET NORTH WILKESBORO NC	DIST	100.00	13.00	
9	BRUSHY CREEK RET GREENVILLE SC	DIST	100.00	13.00	
10	BRUSHY CREEK RET GREENVILLE SC	DIST	100.00	13.00	
11	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
12	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
13	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
14	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	
15	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
16	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	
17	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	
18	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	4.10	
19	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	0.60	
20	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
21	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
22	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	4.10	
23	BUCK STEAM STA YARD SPENCER NC	TRANS	24.00	0.60	
24	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
25	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
26	BUCK STEAM STA YARD SPENCER NC	TRANS	100.00	13.00	13.00
27	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
28	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
29	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
30	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
31	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
32	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
33	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	0.60	
34	BUCK STEAM STA YARD SPENCER NC	TRANS	44.00		
35	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
36	BUCK STEAM STA YARD SPENCER NC	TRANS	13.00	4.10	
37	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		
38	BUCK STEAM STA YARD SPENCER NC	TRANS			
39	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		
40	BUCK STEAM STA YARD SPENCER NC	TRANS	4.10		

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	BUCK TIE SPENCER NC	TRANS	230.00	100.00	44.00
2	BUCK TIE SPENCER NC	TRANS	230.00	100.00	13.00
3	BUCK TIE SPENCER NC	TRANS	100.00	13.80	
4	BUCK TIE SPENCER NC	TRANS	13.00	0.40	
5	BUCK TIE SPENCER NC	TRANS	13.00	0.40	
6	BUCKEYE RET CHARLOTTE NC	DIST	100.00	24.00	
7	BUCKEYE RET CHARLOTTE NC	DIST	100.00	24.00	
8	BURLINGTON MN BURLINGTON NC	DIST	100.00	24.00	
9	BURLINGTON MN BURLINGTON NC	DIST	100.00	24.00	
10	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
11	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
12	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
13	BURLINGTON MN BURLINGTON NC	DIST	24.00	2.40	
14	BUSH RIVER TIE NEWBERRY SC	TRANS	230.00	100.00	44.00
15	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	13.00
16	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	
17	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	100.00	4.10
18	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00		
19	BUSH RIVER TIE NEWBERRY SC	TRANS	100.00	13.00	6.90
20	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
21	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
22	BUSH RIVER TIE NEWBERRY SC	TRANS	44.00	2.40	
23	BUSH RIVER TIE NEWBERRY SC	TRANS	24.00	0.40	
24	BUTNER RET DURHAM NC	DIST	100.00	24.00	
25	BUTNER RET DURHAM NC	DIST	100.00	24.00	
26	BUTNER RET DURHAM NC	DIST	100.00	24.00	
27	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
28	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
29	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	13.00	
30	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	24.00	
31	BUXTON ST RET WINSTON-SALEM NC	DIST	100.00	24.00	
32	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
33	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
34	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	2.40	
35	BUXTON ST RET WINSTON-SALEM NC	DIST	24.00	6.90	2.40
36	BUZZARD ROOST COMB TURBINE CHAPPELLS SC	TRANS	100.00	13.00	13.00
37	BUZZARD ROOST COMB TURBINE CHAPPELLS SC	TRANS	100.00	13.00	
38	BYRUM CREEK RET ANDERSON SC	DIST	100.00	13.00	
39	CAIRO RET NORTH WILKESBORO NC	DIST	100.00	13.00	
40	CAMERON AVE SS CHAPEL HILL NC	TRANS	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CAMERON AVE SS CHAPEL HILL NC	TRANS	100.00	13.00	
2	CAMP CREEK RD RET WHITTIER NC	DIST	69.00	13.00	
3	CAMP CREEK RD RET WHITTIER NC	DIST	69.00	13.00	
4	CAMP CROFT RET SPARTANBURG SC	DIST	100.00	13.00	
5	CAMP CROFT RET SPARTANBURG SC	DIST	100.00	13.00	
6	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
7	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
8	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	100.00	44.00	
9	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	44.00	13.00	
10	CAMPOBELLO TIE CAMPOBELLO SC	TRANS	24.00	0.20	
11	CAMPTON RET INMAN SC	DIST	100.00	13.00	
12	CAMPTON RET INMAN SC	DIST	100.00	13.00	
13	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
14	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
15	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
16	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	44.00
17	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
18	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
19	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	24.00
20	CANE CREEK TIE TAYLORS SC	TRANS	100.00	44.00	
21	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
22	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	
23	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	
24	CANOE CREEK RET MORGANTON NC	DIST	44.00	6.90	
25	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
26	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
27	CANOE CREEK RET MORGANTON NC	DIST	44.00	13.00	6.90
28	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
29	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
30	CARMEL RD RET CHARLOTTE NC	DIST	100.00	13.00	
31	CARSON RET MARION NC	DIST	44.00	13.00	
32	CARSON RET MARION NC	DIST	44.00	13.00	
33	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
34	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
35	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
36	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
37	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
38	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
39	CARVER ST RET CLOVER SC	DIST	44.00	6.90	2.40
40	CASHIERS RET CASHIERS NC	DIST	69.00	13.00	

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1	CASHIERS RET CASHIERS NC	DIST	69.00	13.00	
2	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	230.00	24.00	
3	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
4	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
5	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	13.00	
6	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	230.00	24.00	
7	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
8	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
9	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
10	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
11	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
12	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
13	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
14	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
15	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
16	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
17	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
18	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
19	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
20	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	24.00	6.90	6.90
21	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
22	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
23	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
24	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
25	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
26	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
27	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
28	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
29	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
30	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
31	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
32	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
33	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
34	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
35	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	4.10	
36	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	
37	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	4.10	0.60	
38	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90		
39	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.40	
40	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	6.90	0.60	

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1	CATAWBA NUC STA UNIT 1 ROCK HILL SC	TRANS	13.00	0.60	
2	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	230.00	24.00	
3	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.40	
4	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.40	
5	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
6	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
7	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	13.00	
8	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	230.00	24.00	
9	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
10	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
11	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
12	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
13	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
14	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
15	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
16	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
17	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
18	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
19	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
20	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
21	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
22	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	24.00	6.90	6.90
23	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
24	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
25	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
26	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
27	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
28	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
29	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
30	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	4.10	0.60	
31	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
32	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
33	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	13.00	0.60	
34	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
35	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	0.60	
36	CATAWBA NUC STA UNIT 2 ROCK HILL SC	TRANS	6.90	4.10	
37	CATAWBA RET CATAWBA NC	DIST	44.00	13.00	
38	CATAWBA RET CATAWBA NC	DIST	44.00	13.00	
39	CATFISH RET HICKORY NC	DIST	44.00	13.00	
40	CATFISH RET HICKORY NC	DIST	44.00	13.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CATHEY RD RET ANDERSON SC	DIST	100.00	13.00	
2	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
3	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
4	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	100.00	6.90	
5	CEDAR CREEK HYDRO YARD GREAT FALLS SC	TRANS	0.60	0.20	
6	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
7	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
8	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
9	CENTRAL TIE CENTRAL SC	TRANS	230.00	100.00	44.00
10	CENTRAL TIE CENTRAL SC	TRANS	44.00		
11	CENTRAL TIE CENTRAL SC	TRANS	44.00		
12	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
13	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
14	CENTRAL TIE CENTRAL SC	TRANS	44.00	6.90	2.40
15	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	2.40
16	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
17	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
18	CHAMBERS RET MORGANTON NC	DIST	44.00	6.90	
19	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
20	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
21	CHEROKEE RESERVATION RET CHEROKEE NC	DIST	66.00	13.00	
22	CHERRYVILLE MAIN CHERRYVILLE NC	DIST	44.00	13.00	
23	CHERRYVILLE MAIN CHERRYVILLE NC	DIST	44.00	13.00	
24	CHERRYVILLE RET CHERRYVILLE NC	DIST	44.00	13.00	
25	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
26	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
27	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	100.00	44.00	
28	CHERRYVILLE TIE CHERRYVILLE NC	TRANS	44.00	0.20	
29	CHESNEE RET CHESNEE SC	DIST	44.00	13.00	
30	CHESNEE RET CHESNEE SC	DIST	44.00	13.00	
31	CHESNEE TIE CHESNEE SC	TRANS	100.00	44.00	
32	CHESNEE TIE CHESNEE SC	TRANS	100.00	44.00	
33	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
34	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
35	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
36	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
37	CHESTER MAIN CHESTER SC	DIST	100.00	13.00	6.90
38	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00
39	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00
40	CHESTER MAIN CHESTER SC	DIST	100.00	44.00	13.00

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
2	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
3	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
4	CHESTER MAIN CHESTER SC	DIST	24.00	6.90	2.40
5	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
6	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
7	CHINA GROVE MAIN CHINA GROVE NC	TRANS	100.00	44.00	
8	CHINA GROVE MAIN CHINA GROVE NC	TRANS	24.00	0.20	
9	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
10	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
11	CHINA GROVE RET CHINA GROVE NC	DIST	44.00	2.40	
12	CHINA GROVE RET CHINA GROVE NC	DIST	100.00	13.00	
13	CHRISTOPHER RD RET SHELBY NC	DIST	100.00	13.00	
14	CLAREMONT RET CLAREMONT NC	DIST	100.00	13.00	
15	CLAREMONT RET CLAREMONT NC	DIST	100.00	13.00	
16	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	44.00	
17	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	44.00	
18	CLARK HILL TIE GREENWOOD SC	TRANS	100.00	100.00	
19	CLARK HILL TIE GREENWOOD SC	TRANS	24.00	0.20	
20	CLEGHORN SS RUTHERFORDTON NC	DIST	44.00	13.00	
21	CLEMMONS RET CLEMMONS NC	DIST	100.00	13.00	
22	CLEMMONS RET CLEMMONS NC	DIST	100.00	13.00	
23	CLEMSON UNIV STA 2 CLEMSON SC	DIST	44.00	13.00	
24	CLEMSON UNIV STA 2 CLEMSON SC	DIST	44.00	13.00	
25	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
26	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
27	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
28	CLEVELAND RET CLEVELAND NC	DIST	100.00	13.00	6.90
29	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
30	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
31	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	13.00	
32	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	0.60	2.40
33	CLIFFSIDE STEAM STA 1-4 SW YD CLIFFSIDE NC	TRANS	44.00	0.60	2.40
34	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	24.00	4.10	
35	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	4.10	
36	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	4.10	
37	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
38	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
39	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.40	
40	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	24.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
2	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
3	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
4	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
5	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
6	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
7	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
8	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
9	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
10	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	4.10	0.60	
11	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	100.00	44.00
12	CLIFFSIDE STEAM STA 5 SW YD CLIFFSIDE NC	TRANS	230.00	100.00	44.00
13	CLIMAX RET CLIMAX NC	DIST	44.00	13.00	
14	CLIMAX RET CLIMAX NC	DIST	44.00	13.00	
15	CLINTON CITY CLINTON SC	DIST	100.00	24.00	13.00
16	CLINTON CITY CLINTON SC	DIST	100.00	24.00	13.00
17	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
18	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
19	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
20	CLINTON TIE CLINTON SC	TRANS	100.00	44.00	24.00
21	CLINTON TIE CLINTON SC	TRANS	24.00	0.20	
22	CLOVER TIE CLOVER SC	TRANS	100.00	44.00	
23	CLOVER TIE CLOVER SC	TRANS	100.00	44.00	
24	CLOVER TIE CLOVER SC	TRANS	24.00	0.20	
25	CODDLE CREEK RET MOORESVILLE NC	DIST	44.00	13.00	
26	CODDLE CREEK RET MOORESVILLE NC	DIST	44.00	13.00	
27	COFFEY CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
28	COFFEY CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
29	COLFAX RET COLFAX NC	DIST	100.00	24.00	
30	COLFAX RET COLFAX NC	DIST	100.00	24.00	
31	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
32	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
33	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
34	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	6.90
35	COLUMBUS RET COLUMBUS NC	DIST	44.00	13.00	
36	COMMONWEALTH RET CHARLOTTE NC	DIST	100.00	13.00	
37	COMMONWEALTH RET CHARLOTTE NC	DIST	100.00	13.00	
38	COMMSCOPE SHERRILLS FORD T&D SHERRILLS FORD	DIST	44.00	13.00	
39	COMMSCOPE SHERRILLS FORD T&D SHERRILLS FORD	DIST	44.00	13.00	
40	CONCORD CITY DEL 1 CONCORD NC	DIST	100.00	44.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	CONCORD CITY DEL 1 CONCORD NC	DIST	100.00	44.00	
2	CONCORD CITY DEL 1 CONCORD NC	DIST	24.00	0.20	
3	CONCORD MAIN CONCORD NC	TRANS	100.00	13.00	
4	CONCORD MAIN CONCORD NC	TRANS	100.00	13.00	
5	CONCORD MAIN CONCORD NC	TRANS	100.00	44.00	
6	CONCORD MAIN CONCORD NC	TRANS	100.00	44.00	
7	CONWAY RET GREENVILLE SC	DIST	100.00	13.00	
8	CONWAY RET GREENVILLE SC	DIST	100.00	13.00	
9	CORINTH RET ELLENBORO NC	DIST	44.00	13.00	
10	CORONACA RET CORONACA SC	DIST	44.00	13.00	
11	CORONACA RET CORONACA SC	DIST	44.00	13.00	
12	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
13	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
14	CORONACA TIE CORONACA SC	TRANS	100.00	44.00	
15	CORONACA TIE CORONACA SC	TRANS	24.00	0.20	
16	COTTONWOOD RET CORNELIUS NC	DIST	100.00	13.00	
17	COTTONWOOD RET CORNELIUS NC	DIST	100.00	13.00	
18	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
19	COUNTRYSIDE RD RET KINGS MOUNTAIN NC	DIST	100.00	24.00	
20	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00
21	COWANS FORD HYDRO STANLEY NC	TRANS	230.00	13.00	13.00
22	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	
23	COWANS FORD HYDRO STANLEY NC	TRANS	13.00	0.60	
24	COWANS FORD HYDRO STANLEY NC	TRANS	44.00	0.60	
25	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
26	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
27	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
28	COWPENS RET COWPENS SC	DIST	44.00	6.90	2.40
29	COWPENS RET COWPENS SC	DIST	44.00	13.00	
30	CREST ST RET DURHAM NC	DIST	100.00	6.90	
31	CREST ST RET DURHAM NC	DIST	100.00	6.90	
32	CREST ST RET DURHAM NC	DIST	100.00	6.90	
33	CREST ST RET DURHAM NC	DIST	100.00	6.90	
34	CREST ST RET DURHAM NC	DIST	100.00	6.90	
35	CREST ST RET DURHAM NC	DIST	100.00	6.90	
36	CREST ST RET DURHAM NC	DIST	100.00	6.90	
37	CRETO TIE NINETY SIX SC	TRANS	100.00	44.00	
38	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
39	CRUMP RD RET HUDSON NC	DIST	100.00	13.00	
40	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	

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1	CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
2	CYCLE RET ELKIN NC	DIST	44.00	13.00	
3	CYCLE RET ELKIN NC	DIST	44.00	13.00	
4	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
5	CYPRESS TIE ABBEVILLE SC	TRANS	100.00	44.00	
6	CYPRESS TIE ABBEVILLE SC	TRANS	24.00	0.20	
7	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
8	DACIAN AVE RET DURHAM NC	DIST	100.00	24.00	
9	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
10	DALLAS CITY DEL 2 DALLAS NC	DIST	44.00	13.00	
11	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
12	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
13	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
14	DAN RIVER STEAM STA EDEN NC	TRANS	138.00	100.00	13.80
15	DAN RIVER STEAM STA EDEN NC	TRANS	2.40	0.60	
16	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
17	DAN VALLEY RET STONEVILLE NC	DIST	100.00	13.00	
18	DANBURY RET DANBURY NC	DIST	44.00	24.00	13.00
19	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
20	DANIELS RET GREENVILLE SC	DIST	100.00	13.00	
21	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
22	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
23	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
24	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
25	DAVIDSON RET DAVIDSON NC	DIST	44.00	13.00	
26	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
27	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
28	DAVIDSON RET DAVIDSON NC	DIST	44.00	6.90	2.40
29	DAVIDSON RIVER RET PISGAH FOREST NC	TRANS	100.00	13.00	
30	DAVIS RET WILLIAMSTON SC	DIST	100.00	13.00	
31	DEARBORN HYDRO GREAT FALLS SC	TRANS	100.00	66.00	
32	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
33	DEARBORN HYDRO GREAT FALLS SC	TRANS	44.00	6.90	
34	DEERFIELD RET MOORESVILLE NC	DIST	100.00	13.00	
35	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
36	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
37	DENNY RD RET GREENSBORO NC	DIST	100.00	24.00	
38	DENTON RET DENTON NC	DIST	100.00	13.00	
39	DEPOT ST RET FRANKLIN NC	DIST	66.00		
40	DEPOT ST RET FRANKLIN NC	DIST	69.00	13.00	

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1	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
2	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
3	DERITA RET CHARLOTTE NC	DIST	100.00	24.00	
4	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
5	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
6	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
7	DILWORTH DIST CHARLOTTE NC	DIST	24.00	2.40	0.60
8	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
9	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
10	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
11	DILWORTH DIST CHARLOTTE NC	DIST	24.00	6.90	2.40
12	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
13	DIXIE TIE GASTONIA NC	TRANS	100.00	44.00	
14	DIXIE TIE GASTONIA NC	TRANS	100.00	0.20	
15	DIXON RET ANDERSON SC	DIST	100.00	13.00	
16	DOBSON RET DOBSON NC	DIST	44.00	6.90	
17	DOBSON RET DOBSON NC	DIST	44.00	6.90	
18	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
19	DOBSON RET DOBSON NC	DIST	44.00	6.90	2.40
20	DOCHENO RET HONEA PATH SC	DIST	44.00	13.00	
21	DOCHENO RET HONEA PATH SC	DIST	44.00	13.00	
22	DRAKA COMTEQ T&D CLAREMONT NC	DIST	100.00	24.00	13.00
23	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
24	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
25	DUKE UNIV MN DURHAM NC	DIST	100.00	44.00	
26	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
27	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
28	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
29	DUKE UNIV MN DURHAM NC	DIST	24.00	0.20	
30	DUKE UNIV STA 1 DURHAM NC	DIST	44.00	13.00	
31	DUKE UNIV STA 1 DURHAM NC	DIST	44.00	13.00	
32	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
33	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
34	DUKE UNIV STA 2 DURHAM NC	DIST	44.00	13.00	
35	DUKE UNIV STA 3 DURHAM NC	DIST	44.00	13.00	
36	DUKE UNIV STA 3 DURHAM NC	DIST	44.00	13.00	
37	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
38	DUKE UNIV STA 4 DURHAM NC	DIST	44.00	13.00	
39	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	
40	DUNBAR RET MOORESVILLE NC	DIST	100.00	13.00	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
2	DUNCAN RET DUNCAN SC	DIST	44.00	13.00	
3	DURHAM MN DURHAM NC	DIST	100.00	13.00	
4	DURHAM MN DURHAM NC	DIST	100.00	13.00	
5	DURHAM MN DURHAM NC	DIST	100.00	13.00	
6	E BRYSON RET BRYSON CITY NC	DIST	66.00	13.00	
7	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
8	E CHESTER RET CHESTER SC	DIST	100.00	13.00	
9	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
10	E DURHAM TIE DURHAM NC	TRANS	230.00	100.00	44.00
11	E DURHAM TIE DURHAM NC	TRANS	44.00	0.40	
12	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
13	E FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
14	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
15	E GANTT RET CONESTEE SC	DIST	44.00	13.00	
16	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	
17	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
18	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
19	E MAIDEN RET MAIDEN NC	DIST	44.00	6.90	2.40
20	E MAIDEN RET MAIDEN NC	DIST	44.00	13.00	
21	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
22	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
23	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
24	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
25	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
26	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
27	E SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	6.90	2.40
28	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
29	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
30	E SPARTANBURG TIE SPARTANBURG SC	TRANS	44.00	6.90	2.40
31	E SYLVA RET SYLVA NC	DIST	66.00	13.00	
32	E SYLVA RET SYLVA NC	DIST	66.00	13.00	
33	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
34	E THOMASVILLE RET THOMASVILLE NC	DIST	100.00	13.00	
35	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	24.00	13.00
36	EASLEY CITY DEL 3 EASLEY SC	DIST	100.00	44.00	24.00
37	EASLEY CITY DEL 4 EASLEY SC	DIST	100.00	13.00	
38	EASLEY MN EASLEY SC	TRANS	100.00	13.00	
39	EASLEY MN EASLEY SC	TRANS	100.00	13.00	
40	EASLEY MN EASLEY SC	TRANS	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	EASLEY MN EASLEY SC	TRANS	100.00	44.00	
2	EASLEY MN EASLEY SC	TRANS	100.00	44.00	
3	EASTATOE RET PICKENS SC	DIST	100.00	13.00	
4	EASTFIELD RD RET CONCORD NC	DIST	100.00	13.00	
5	EASTFIELD RD RET CONCORD NC	DIST	100.00	24.00	
6	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
7	EASTGATE RET CHAPEL HILL NC	DIST	100.00	13.00	
8	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
9	EASTOVER RET GREENVILLE SC	DIST	100.00	13.00	
10	EASY ST RET CONCORD NC	DIST	44.00	13.00	
11	EBENEZER RET TRAVELERS REST SC	DIST	100.00	13.00	
12	EBERT RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
13	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
14	EDNEYVILLE RET HENDERSONVILLE NC	DIST	44.00	13.00	
15	EFLAND RET EFLAND NC	DIST	44.00	13.00	
16	EFLAND RET EFLAND NC	DIST	44.00	13.00	
17	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
18	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
19	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	24.00	
20	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
21	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
22	ELIZABETH AVE RET CHARLOTTE NC	DIST	100.00	13.00	
23	ELIZABETH AVE RET CHARLOTTE NC	DIST	24.00	4.10	2.40
24	ELIZABETH AVE RET CHARLOTTE NC	DIST	24.00	4.10	
25	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
26	ELK VALLEY RET ELKIN NC	DIST	100.00	13.00	
27	ELKIN RET ELKIN NC	DIST	44.00	2.40	
28	ELKIN RET ELKIN NC	DIST	44.00	2.40	
29	ELKIN RET ELKIN NC	DIST	44.00	2.40	
30	ELKIN RET ELKIN NC	DIST	44.00	2.40	0.60
31	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
32	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
33	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
34	ELKIN RET ELKIN NC	DIST	44.00	6.90	2.40
35	ELLERBEE RET CHAPEL HILL NC	DIST	100.00	13.00	
36	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
37	ELLIOTT RET SHELBY NC	DIST	100.00	13.00	
38	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
39	ELLIS RD RET DURHAM NC	DIST	100.00	24.00	
40	ELMWOOD RET ELMWOOD NC	DIST	100.00	24.00	

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1	EMERALD RD RET GREENWOOD SC	DIST	100.00	13.00	
2	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
3	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
4	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
5	ENERGYUNITED EMC DEL 11 TAYLORSVILLE NC	DIST	100.00	24.00	13.00
6	ENO RET DURHAM NC	DIST	44.00	24.00	
7	ENO RET DURHAM NC	DIST	44.00	24.00	13.00
8	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
9	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
10	ENO TIE DURHAM NC	TRANS	230.00	100.00	44.00
11	ENO TIE DURHAM NC	TRANS	230.00	100.00	13.00
12	ENO TIE DURHAM NC	TRANS	44.00		
13	ENO TIE DURHAM NC	TRANS	44.00		
14	ENO TIE DURHAM NC	TRANS	44.00	0.40	
15	ENO TIE DURHAM NC	TRANS	13.00	0.40	0.20
16	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	
17	ENOCHVILLE RET KANNAPOLIS NC	DIST	100.00	13.00	
18	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	
19	ENOLA RET SPARTANBURG SC	DIST	100.00	13.00	
20	FAIR GROVE RET THOMASVILLE NC	DIST	100.00	13.00	
21	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
22	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
23	FAIRFAX RD RET GREENSBORO NC	DIST	100.00	24.00	
24	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
25	FAIRNTOSH RET DURHAM NC	DIST	100.00	24.00	
26	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
27	FAIRPLAINS RET NORTH WILKESBORO NC	DIST	100.00	13.00	
28	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
29	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
30	FAIRVIEW TIE FOREST CITY NC	TRANS	100.00	44.00	
31	FAITH RET SALISBURY NC	DIST	100.00	13.00	
32	FAITH RET SALISBURY NC	DIST	100.00	13.00	
33	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
34	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
35	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
36	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
37	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
38	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	
39	FALL CREEK RET JONESVILLE NC	DIST	44.00	6.90	2.40
40	FANTS GROVE RET PENDLETON SC	DIST	44.00	13.00	

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1	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
2	FANTS GROVE RET PENDLETON SC	DIST	44.00	24.00	
3	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
4	FIDDLERS CREEK RET WINSTON-SALEM NC	DIST	100.00	13.00	
5	FINGERVILLE RET FINGERVILLE SC	DIST	100.00	13.00	
6	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
7	FIRST ST RET HICKORY NC	DIST	44.00	13.00	4.10
8	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
9	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
10	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
11	FIRST ST RET HICKORY NC	DIST	44.00	6.90	2.40
12	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
13	FISHER SS CHARLOTTE NC	DIST	100.00	24.00	
14	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
15	FISHER SS CHARLOTTE NC	DIST	24.00	4.10	
16	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	
17	FISHING CREEK HYDRO GREAT FALLS SC	TRANS	100.00	6.90	
18	FITESA SIMPSONVILLE T&D FOUNTAIN INN SC	DIST	100.00	24.00	
19	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
20	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
21	FLAT ROCK RET ANDERSON SC	DIST	44.00	13.00	
22	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
23	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
24	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
25	FLAY RET LINCOLNTON NC	DIST	44.00	6.90	2.40
26	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
27	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
28	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	6.90	2.40
29	FLORIDA AVE RET GREENWOOD SC	DIST	44.00	13.00	
30	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
31	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
32	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
33	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
34	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
35	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
36	FOREST CITY DEL 2 FOREST CITY NC	DIST	44.00	6.90	2.40
37	FOREST CITY DEL 3 FOREST CITY NC	DIST	44.00	13.00	
38	FOREST CITY DEL 3 FOREST CITY NC	DIST	44.00	13.00	
39	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	
40	FOREST HILL RET GREENWOOD SC	DIST	44.00	13.00	

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1	FOREST LAKE RET FORT MILL SC	DIST	44.00	24.00	
2	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
3	FOUR SEASONS RET CHARLOTTE NC	DIST	100.00	24.00	
4	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
5	FRIEDEN RET GIBSONVILLE NC	DIST	100.00	24.00	
6	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
7	FRIENDSHIP RET GREENSBORO NC	DIST	100.00	24.00	
8	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
9	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
10	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
11	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
12	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
13	FRONTIER SPINNING M PL 3 MAYODAN NC	DIST	44.00	0.20	
14	FURR RD RET HUNTERSVILLE NC	DIST	44.00	13.00	
15	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
16	GAFFNEY CITY DEL 1A & 1B GAFFNEY SC	DIST	100.00	24.00	
17	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
18	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
19	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
20	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
21	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
22	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
23	GAFFNEY TIE GAFFNEY SC	TRANS	100.00	24.00	
24	GAFFNEY TIE GAFFNEY SC	TRANS	44.00	0.20	
25	GAFFNEY TIE GAFFNEY SC	TRANS	44.00	0.20	
26	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
27	GARRETT RD RET DURHAM NC	DIST	100.00	24.00	
28	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
29	GASTONIA CITY DEL 10 GASTONIA NC	DIST	100.00	13.00	
30	GASTONIA CITY DEL 10 GASTONIA NC	DIST			
31	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
32	GASTONIA CITY DEL 11 GASTONIA NC	DIST	100.00	13.00	
33	GASTONIA CITY DEL 12 GASTONIA NC	DIST	100.00	13.00	
34	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	
35	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
36	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
37	GASTONIA CITY DEL 2 GASTONIA NC	DIST	44.00	6.90	2.40
38	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
39	GASTONIA CITY DEL 6 GASTONIA NC	DIST	100.00	13.00	
40	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40

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1	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
2	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
3	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	6.90	2.40
4	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
5	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
6	GASTONIA CITY DEL 7 GASTONIA NC	DIST	44.00	13.00	6.90
7	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
8	GASTONIA CITY DEL 9 GASTONIA NC	DIST	100.00	13.00	
9	GASTONIA CITY DEL 12 GASTONIA NC	TRANS	100.00	13.00	
10	GATEWAY RET WHITTIER NC	DIST	66.00	13.00	
11	GATEWAY RET WHITTIER NC	DIST	66.00		
12	GATEWOOD RET GATEWOOD NC	DIST	44.00	13.00	
13	GENELEE RET DURHAM NC	DIST	100.00	24.00	
14	GENELEE RET DURHAM NC	DIST	100.00	24.00	
15	GENESTU DR RET CHAPEL HILL NC	TRANS	100.00	13.09	
16	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
17	GILBREATH RET GRAHAM NC	DIST	100.00	24.00	
18	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	
19	GILBREATH RET GRAHAM NC	DIST	24.00	13.00	
20	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	13.00	
21	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
22	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
23	GLEN ALPINE RET GLEN ALPINE NC	DIST	44.00	6.90	
24	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
25	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
26	GLEN RAVEN MN GLEN RAVEN NC	TRANS	100.00	24.00	
27	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
28	GLENOLA RET GLENOLA NC	DIST	100.00	13.00	
29	GLENWAY SS STATESVILLE NC	DIST	100.00	24.00	
30	GLENWOOD RET MARION NC	DIST	100.00	13.00	
31	GLENWOOD RET MARION NC	DIST	100.00	13.00	
32	GOODWILL CHURCH RD RET BELEWS CREEK NC	DIST	100.00	13.00	
33	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
34	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	13.00	
35	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
36	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
37	GRAHAM ST RET CHARLOTTE NC	DIST	100.00	24.00	
38	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
39	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
40	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GRAHAM ST RET CHARLOTTE NC	DIST	13.00	2.40	
2	GRANITE FALLS CITY DEL 2 GRANITE FALLS NC	DIST	44.00	13.00	
3	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
4	GRASSY POND RET GRASSY POND SC	DIST	44.00	13.00	
5	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
6	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
7	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
8	GREAT FALLS HYDRO STA GREAT FALLS SC	TRANS	44.00	2.40	
9	GREAT FALLS SW STA GREAT FALLS SC	TRANS	100.00	44.00	
10	GREAT FALLS SW STA GREAT FALLS SC	TRANS	100.00	44.00	
11	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
12	GREEN POND RET ANDERSON SC	DIST	44.00	13.00	
13	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
14	GREEN ST RET DURHAM NC	DIST	100.00	13.00	
15	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
16	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
17	GREENBRIAR SW STA SIMPSONVILLE SC	DIST	100.00	13.00	
18	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
19	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
20	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
21	GREENSBORO MN GREENSBORO NC	TRANS	100.00	6.90	2.40
22	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
23	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
24	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
25	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
26	GREENSBORO MN GREENSBORO NC	TRANS	100.00	24.00	
27	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
28	GREENVILLE MN GREENVILLE SC	TRANS	100.00	13.00	
29	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
30	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
31	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	24.00
32	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
33	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
34	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
35	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
36	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
37	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
38	GREENVILLE MN GREENVILLE SC	TRANS	100.00	44.00	
39	GREENVILLE MN GREENVILLE SC	TRANS	24.00	0.20	
40	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	GREENWOOD CITY DEL 1 GREENWOOD SC	DIST	44.00	13.00	
2	GREENWOOD CITY DEL 3 GREENWOOD SC	DIST	44.00	13.00	
3	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
4	GREENWOOD CITY DEL 4 GREENWOOD SC	DIST	44.00	13.00	
5	GREENWOOD CITY DEL 5 GREENWOOD SC	DIST	44.00	13.00	
6	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
7	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
8	GREENWOOD TIE GREENWOOD SC	TRANS	100.00	44.00	
9	GREENWOOD TIE GREENWOOD SC	TRANS	24.00	0.20	
10	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
11	GREER CITY STA 2 GREER SC	DIST	100.00	13.00	4.10
12	GREER RET GREER SC	DIST	100.00	13.00	
13	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
14	GREY RET CHAPEL HILL NC	DIST	100.00	13.00	
15	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
16	GRIFFITH RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
17	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
18	GROOMTOWN RET GREENSBORO NC	DIST	100.00	24.00	
19	GROOMTOWN RET GREENSBORO NC	DIST	100.00	13.00	
20	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
21	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
22	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
23	GTP GREENVILLE INC GREENVILLE SC	DIST	44.00	2.40	
24	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
25	GUTHRIE RET WINSTON-SALEM NC	DIST	100.00	13.00	
26	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
27	HAMPTON AVE RET SPARTANBURG SC	DIST	100.00	13.00	
28	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
29	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
30	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
31	HAMPTON AVE RET SPARTANBURG SC	DIST	44.00	2.40	
32	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
33	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
34	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
35	HARRISBURG TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
36	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00		
37	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
38	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
39	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	0.60	
40	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
2	HARRISBURG TIE CHARLOTTE NC	TRANS	44.00	2.40	0.60
3	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
4	HARTFORD AVE RET BESSEMER CITY NC	DIST	44.00	13.00	
5	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
6	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
7	HAW RIVER RET HAW RIVER NC	DIST	44.00	13.00	
8	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
9	HAW RIVER RET HAW RIVER NC	DIST	13.00	2.40	0.60
10	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
11	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
12	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
13	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
14	HAWTHORNE RD RET WINSTON-SALEM NC	DIST	100.00	13.00	
15	HAYS RET HAYS NC	DIST	44.00	13.00	
16	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
17	HEATH RET RANDLEMAN NC	DIST	100.00	13.00	
18	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	
19	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	100.00	44.00	
20	HENDERSONVILLE TIE EAST FLAT ROCK NC	TRANS	24.00	0.20	
21	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
22	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
23	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
24	HENSLEY RD RET FORT MILL SC	DIST	13.00	2.40	
25	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
26	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
27	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
28	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
29	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
30	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
31	HENSLEY RD RET FORT MILL SC	DIST	44.00	6.90	
32	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
33	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
34	HICKORY GROVE RET CHARLOTTE NC	DIST	100.00	13.00	
35	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
36	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
37	HICKORY TIE HICKORY NC	TRANS	100.00	44.00	
38	HICKORY TIE HICKORY NC	TRANS	24.00	0.20	
39	HIDDENITE RET HIDDENITE NC	DIST	44.00	13.00	
40	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	
2	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
3	HIDDENITE RET HIDDENITE NC	DIST	44.00	6.90	2.40
4	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
5	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
6	HIGH SHOALS RET HIGH SHOALS NC	DIST	13.00	2.40	
7	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	
8	HIGH SHOALS RET HIGH SHOALS NC	DIST	44.00	13.00	13.00
9	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
10	HIGHLANDS RET HIGHLANDS NC	DIST	66.00	13.00	
11	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
12	HIGHTOWER RET TAYLORS SC	DIST	100.00	13.00	
13	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
14	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
15	HILL ST RET CHARLOTTE NC	DIST	100.00	24.00	
16	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
17	HILLBROOK RET SPARTANBURG SC	DIST	100.00	13.00	
18	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
19	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
20	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
21	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	
22	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	
23	HILLSBOROUGH RET HILLSBOROUGH NC	DIST	44.00	6.90	2.40
24	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
25	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
26	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
27	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	100.00	44.00	
28	HILLTOP TIE KINGS MOUNTAIN NC	TRANS	24.00	0.20	
29	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
30	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
31	HINSHAW RET WINSTON-SALEM NC	DIST	100.00	13.00	
32	HITACHI METALS LTD CHINA GROVE NC	DIST	44.00	13.00	
33	HOLCOMBE RD RET PIEDMONT SC	DIST	100.00	13.00	
34	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
35	HOLLY HILL RET THOMASVILLE NC	DIST	100.00	13.00	
36	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
37	HOMESTEAD RET CHAPEL HILL NC	DIST	100.00	13.00	
38	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
39	HOPE VALLEY RET DURHAM NC	DIST	100.00	13.00	
40	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
2	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
3	HOPEDALE DIST HOPEDALE NC	DIST	24.00	6.90	2.40
4	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
5	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	100.00	13.00
6	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
7	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
8	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
9	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
10	HORSESHOE TIE HENDERSONVILLE NC	TRANS	100.00	44.00	
11	HORSESHOE TIE HENDERSONVILLE NC	TRANS	24.00	0.20	
12	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
13	HORTON RD RET DURHAM NC	DIST	100.00	13.00	
14	HUDLOW RET RUTHERFORDTON NC	DIST	100.00	13.00	
15	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
16	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
17	HUDSON ST RET GREENVILLE SC	DIST	100.00	13.00	
18	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
19	HUNTERSVILLE CITY HUNTERSVILLE NC	DIST	44.00	13.00	
20	HURRICANE CREEK RET ANDERSON SC	DIST	100.00	13.00	
21	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
22	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	13.00	
23	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
24	IBM CHARLOTTE PL SS CHARLOTTE NC	DIST	100.00	24.00	
25	ICARD RET ICARD NC	DIST	44.00	6.90	
26	ICARD RET ICARD NC	DIST	44.00	6.90	
27	ICARD RET ICARD NC	DIST	44.00	6.90	
28	ICARD RET ICARD NC	DIST	44.00	6.90	
29	ICARD RET ICARD NC	DIST	44.00	6.90	
30	ICARD RET ICARD NC	DIST	44.00	6.90	
31	ICARD RET ICARD NC	DIST	44.00	6.90	
32	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
33	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
34	IMPERIAL RET DURHAM NC	DIST	100.00	24.00	
35	INDIAN LAND RET FORT MILL SC	DIST	100.00	13.00	
36	INDIAN LAND RET FORT MILL SC	DIST	100.00	24.00	
37	INMAN TIE INMAN SC	TRANS	100.00	44.00	
38	INMAN TIE INMAN SC	TRANS	100.00	44.00	
39	INMAN TIE INMAN SC	TRANS	100.00	44.00	
40	ISLAND FORD RD RET STATESVILLE NC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	6.90
2	JAMES ST RET CHAPEL HILL NC	DIST	100.00	13.00	
3	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
4	JENKINS BRANCH RET BRYSON CITY NC	DIST	66.00	13.00	
5	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
6	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
7	JESSUPTOWN RET GREENSBORO NC	DIST	100.00	24.00	
8	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
9	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
10	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
11	JOCASSEE HYDRO JOCASSEE SC	TRANS	230.00	13.00	
12	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
13	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
14	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
15	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
16	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
17	JOCASSEE HYDRO JOCASSEE SC	TRANS	44.00	0.60	0.60
18	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
19	JOCASSEE HYDRO JOCASSEE SC	TRANS	4.10	0.60	
20	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
21	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.40	
22	JOCASSEE HYDRO JOCASSEE SC	TRANS	13.00	0.60	
23	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
24	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
25	JOCASSEE TIE JOCASSEE SC	TRANS	500.00	230.00	24.00
26	JOCASSEE TIE JOCASSEE SC	TRANS	230.00	13.00	13.00
27	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
28	JOHNS CREEK RET GREENWOOD SC	DIST	100.00	13.00	
29	JULIAN RD RET SALISBURY NC	DIST	100.00	13.00	
30	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
31	KANUGA RET HENDERSONVILLE NC	DIST	44.00	13.00	
32	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
33	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
34	KENILWORTH RET CHARLOTTE NC	DIST	100.00	13.00	
35	KEOWEE HYDRO NEWRY SC	TRANS	230.00	13.00	13.00
36	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
37	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
38	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	
39	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.20	
40	KEOWEE HYDRO NEWRY SC	TRANS	13.00	0.60	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	KEOWEE HYDRO NEWRY SC	TRANS	4.10	0.60	
2	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
3	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
4	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
5	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	44.00	13.00
6	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
7	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
8	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	13.00	6.90
9	KERNERSVILLE RET KERNERSVILLE NC	DIST	100.00	24.00	13.00
10	KERSHAW RET KERSHAW SC	DIST	46.00	44.00	
11	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
12	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
13	KERSHAW RET KERSHAW SC	DIST	46.00	44.00	2.40
14	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
15	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
16	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
17	KERSHAW RET KERSHAW SC	DIST	44.00	6.90	2.40
18	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	
19	KEY ST RET PILOT MOUNTAIN NC	DIST	44.00	13.00	
20	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
21	KILDARE RET GREENSBORO NC	DIST	100.00	24.00	
22	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
23	KIMESVILLE RET KIMESVILLE NC	DIST	44.00	13.00	
24	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
25	KINCAID RD RET HUDSON NC	DIST	100.00	13.00	
26	KING RET KING NC	DIST	100.00	13.00	
27	KING RET KING NC	DIST	100.00	13.00	
28	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
29	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
30	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
31	KINGS MTN CITY DEL 2 KINGS MOUNTAIN NC	DIST	44.00	6.90	2.40
32	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
33	KINGS MTN MAIN KINGS MOUNTAIN NC	DIST	44.00	13.00	
34	KINGSGATE RET GREENVILLE SC	DIST	100.00	13.00	
35	KIT CREEK RET DURHAM NC	DIST	100.00	24.00	
36	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
37	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
38	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
39	KIVETT DR RET HIGH POINT NC	DIST	100.00	13.00	6.90
40	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00

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1	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
2	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
3	KIVETT DR RET HIGH POINT NC	DIST	24.00	13.00	13.00
4	KNIGHTS RET ROCK HILL SC	DIST	100.00	24.00	
5	KNIGHTS RET ROCK HILL SC	DIST	100.00	24.00	
6	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
7	KNOLLWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
8	KUDZU RET CHARLOTTE NC	DIST	100.00	24.00	
9	KUDZU RET CHARLOTTE NC	DIST	100.00	13.00	
10	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
11	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
12	LAKE EMORY TIE FRANKLIN NC	TRANS	161.00	66.00	
13	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
14	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
15	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	0.60
16	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
17	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
18	LAKE EMORY TIE FRANKLIN NC	TRANS	44.00	2.40	
19	LAKE EMORY TIE FRANKLIN NC	TRANS	66.00	2.40	
20	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
21	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
22	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
23	LAKE LURE RET LAKE LURE NC	DIST	44.00	6.90	2.40
24	LAKE LURE RET LAKE LURE NC	DIST	44.00	13.00	
25	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
26	LAKE TOWNSEND RET GREENSBORO NC	DIST	100.00	24.00	
27	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
28	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
29	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
30	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	6.90	
31	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
32	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
33	LAKEWOOD RET CHARLOTTE NC	DIST	100.00	13.00	6.90
34	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
35	LAKEWOOD RET CHARLOTTE NC	DIST	44.00	4.10	
36	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
37	LAKEWOOD TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
38	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
39	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00		
40	LAKEWOOD TIE CHARLOTTE NC	TRANS	44.00	0.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
2	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
3	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
4	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	
5	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
6	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
7	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
8	LANCASTER MN LANCASTER SC	TRANS	100.00	44.00	24.00
9	LANCASTER MN LANCASTER SC	TRANS	24.00	0.20	
10	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
11	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
12	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
13	LANCASTER RET LANCASTER SC	DIST	100.00	2.40	
14	LANCASTER RET LANCASTER SC	DIST	100.00	13.00	
15	LANCASTER RET LANCASTER SC	DIST	100.00	13.00	
16	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
17	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
18	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
19	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	2.40	
20	LANDIS CITY DEL 1&2 LANDIS NC	DIST	44.00	13.00	
21	LANDO RET LANDO SC	DIST	44.00	13.00	
22	LANDO RET LANDO SC	DIST	44.00	13.00	
23	LANDRUM RET LANDRUM SC	DIST	44.00	13.00	
24	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
25	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
26	LANDRUM RET LANDRUM SC	DIST	44.00	6.90	
27	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
28	LANGSTON CREEK RET GREENVILLE SC	DIST	100.00	13.00	
29	LANGTREE RET MOORESVILLE NC	DIST	100.00	13.00	
30	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
31	LAUREL CREEK RET GREENVILLE SC	DIST	100.00	13.00	
32	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
33	LAURENS CITY CAROLINE STA LAURENS SC	DIST	100.00	13.00	
34	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	
35	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
36	LAURENS E C DEL 10 LAURENS LAURENS SC	DIST	44.00	6.90	2.40
37	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	4.10
38	LAURENS E C DEL 25 MAULDIN MAULDIN SC	DIST	100.00	13.00	
39	LAURENS E C DEL 26 WALNUT GROVE SC	DIST	100.00	13.00	
40	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
2	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
3	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
4	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
5	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
6	LAURENS TIE LAURENS SC	TRANS	100.00	24.00	
7	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
8	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
9	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
10	LAURENS TIE LAURENS SC	TRANS	44.00	13.00	6.90
11	LAWNDALE RET LAWNDALE NC	DIST	44.00	13.00	
12	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
13	LAWSONS FORK TIE SPARTANBURG SC	TRANS	100.00	44.00	
14	LEAFCREST RET CHARLOTTE NC	DIST	100.00	13.00	
15	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
16	LEE STEAM STA COMB TURB PELZER SC	TRANS	100.00	13.00	
17	LELIA RET WELLFORD SC	DIST	100.00	12.50	
18	LELIA RET WELLFORD SC	DIST	100.00	13.00	
19	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
20	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
21	LESLIE RET LESLIE SC	DIST	44.00	6.90	2.40
22	LESLIE RET LESLIE SC	DIST	44.00	6.90	
23	LESLIE RET LESLIE SC	DIST	44.00	13.00	
24	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
25	LEWISVILLE RET LEWISVILLE NC	DIST	100.00	13.00	
26	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
27	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	100.00	44.00	
28	LEXINGTON CITY DEL 1 LEXINGTON NC	DIST	24.00	0.20	
29	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
30	LEXINGTON MN LEXINGTON NC	DIST	100.00	24.00	
31	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
32	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
33	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
34	LEXINGTON MN LEXINGTON NC	DIST	100.00	13.00	6.90
35	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
36	LIBERTY RET NEW LIBERTY SC	DIST	100.00	13.00	
37	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
38	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
39	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
40	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	

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1	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
2	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
3	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
4	LINCOLN COMBUSTION TURB YARD LOWESVILLE NC	TRANS	230.00	13.00	
5	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
6	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
7	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
8	LINCOLNTON CITY LINCOLNTON NC	DIST	100.00	13.00	6.90
9	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	13.00	
10	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	13.00	
11	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
12	LINCOLNTON TIE LINCOLNTON NC	TRANS	100.00	44.00	
13	LINDE LLC MIDLAND NC	TRANS	100.00	13.00	
14	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
15	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
16	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
17	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	24.00	13.00
18	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
19	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
20	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
21	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	6.90	
22	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	6.90	
23	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
24	LINDEN ST SW STA HIGH POINT NC	DIST	100.00	13.00	6.90
25	LINWOOD SS LEXINGTON NC	DIST	100.00	44.00	24.00
26	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
27	LIONS MOUNTAIN TIE CALVERT NC	TRANS	100.00	44.00	
28	LIONS MOUNTAIN TIE CALVERT NC	TRANS	44.00	4.10	2.40
29	LIONS MOUNTAIN TIE CALVERT NC	TRANS		4.60	
30	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
31	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	13.00	
32	LITTLE ROCK RET CHARLOTTE NC	DIST	100.00	24.00	
33	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
34	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	100.00	44.00	33.00
35	LOCKHART POWER CO DEL 1 PACOLET SC	DIST	33.00		
36	LOCUST RET LOCUST NC	DIST	100.00	13.00	
37	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
38	LONG FERRY RET SALISBURY NC	DIST	100.00	13.00	
39	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	
40	LONGVIEW RET LONG VIEW NC	DIST	44.00	13.00	

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1	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
2	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
3	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
4	LONGVIEW TIE LONG VIEW NC	TRANS	230.00	100.00	44.00
5	LONGVIEW TIE LONG VIEW NC	TRANS	44.00		
6	LONGVIEW TIE LONG VIEW NC	TRANS	44.00		
7	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
8	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
9	LONGVIEW TIE LONG VIEW NC	TRANS	44.00	6.90	2.40
10	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
11	LOOKOUT HYDRO STATESVILLE NC	TRANS	100.00	6.90	
12	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
13	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
14	LOOKOUT TIE STATESVILLE NC	TRANS	100.00	44.00	
15	LOOKOUT TIE STATESVILLE NC	TRANS	24.00	0.20	
16	LUMBER LANE RET MOUNT HOLLY NC	DIST	100.00	13.00	
17	LUNSFORD RD RET KING NC	DIST	100.00	13.00	
18	MACEDONIA RET TAYLORSVILLE NC	DIST	100.00	13.00	
19	MADISON RET MADISON NC	DIST	100.00	13.00	
20	MADISON RET MADISON NC	DIST	100.00	13.00	
21	MADISON TIE MADISON NC	TRANS	100.00	44.00	
22	MADISON TIE MADISON NC	TRANS	100.00	44.00	
23	MADISON TIE MADISON NC	TRANS	100.00	44.00	
24	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
25	MAIDEN CITY DEL 2 MAIDEN NC	DIST	44.00	13.00	
26	MAJOLICA RD RET SALISBURY NC	DIST	100.00	13.00	
27	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
28	MALLARD CREEK RET CHARLOTTE NC	DIST	100.00	13.00	
29	MANCHESTER RET KANNAPOLIS NC	DIST	100.00	13.00	
30	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
31	MARBLE TIE MARBLE NC	TRANS	161.00	34.50	
32	MARBLE TIE MARBLE NC	TRANS	34.50	13.00	
33	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
34	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
35	MARBLE TIE MARBLE NC	TRANS	13.00	0.40	
36	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	13.00	
37	MAR-DON DR RET WINSTON-SALEM NC	DIST	100.00	24.00	
38	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
39	MARIETTA TIE MARIETTA SC	TRANS	100.00	44.00	
40	MARIETTA TIE MARIETTA SC	TRANS	24.00	0.20	

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MARION MN MARION NC	DIST	100.00	13.00	6.90
2	MARION MN MARION NC	DIST	100.00	13.00	6.90
3	MARION MN MARION NC	DIST	100.00	13.00	6.90
4	MARION MN MARION NC	DIST	100.00	13.00	6.90
5	MARION MN MARION NC	DIST	44.00	6.90	2.40
6	MARION MN MARION NC	DIST	44.00	6.90	2.40
7	MARION MN MARION NC	DIST	44.00	6.90	2.40
8	MARION MN MARION NC	DIST	44.00	6.90	2.40
9	MARKET POINT RET GREENVILLE SC	DIST	100.00	13.00	
10	MARSHALL RET TERRELL NC	DIST	44.00	13.00	
11	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
12	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
13	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
14	MARSHALL STEAM STA YARD TERRELL NC	TRANS	230.00	24.00	
15	MARSHALL STEAM STA YARD TERRELL NC	TRANS	4.10	0.60	
16	MARSHALL STEAM STA YARD TERRELL NC	TRANS	4.10	0.60	
17	MARSHALL STEAM STA YARD TERRELL NC	TRANS			
18	MARSHALL STEAM STA YARD TERRELL NC	TRANS			
19	MASONIC DR DIST GREENSBORO NC	DIST	13.00	2.40	
20	MASONIC DR DIST GREENSBORO NC	DIST	13.00	2.40	
21	MASCOT RET INMAN SC	DIST	44.00	13.00	
22	MASCOT RET INMAN SC	DIST	44.00	13.00	
23	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
24	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
25	MATTHEWS RET CHARLOTTE NC	DIST	100.00	24.00	
26	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
27	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
28	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	100.00	44.00	
29	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
30	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	44.00	13.00	
31	MCADENVILLE JCT TIE MCADENVILLE NC	TRANS	24.00	0.20	
32	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
33	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
34	MCALPINE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
35	MCDOWELL TIE MARION NC	TRANS	230.00	100.00	44.00
36	MCDOWELL TIE MARION NC	TRANS	100.00	44.00	
37	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
38	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
39	MCDOWELL TIE MARION NC	TRANS	44.00	24.00	
40	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
2	MCDOWELL TIE MARION NC	TRANS	44.00	2.40	0.60
3	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
4	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
5	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
6	MCGUIRE RET HUNTERSVILLE NC	DIST	44.00	6.90	2.40
7	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	525.00	230.00	22.90
8	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	525.00	230.00	22.90
9	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	525.00	230.00	22.90
10	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	525.00	230.00	22.90
11	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	6.90	4.10	
12	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	25.00	4.20	
13	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.10	0.48	
14	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.16	0.48	
15	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.10	0.48	
16	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	4.10	0.48	
17	MCGUIRE SWITCHING STA HUNTERSVILLE NC	TRANS	500.00		
18	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
19	MEADOW GREEN RET EDEN NC	DIST	100.00	13.00	
20	MEBANE RET MEBANE NC	DIST	44.00	2.40	
21	MEBANE RET MEBANE NC	DIST	44.00	2.40	
22	MEBANE RET MEBANE NC	DIST	44.00	2.40	
23	MEBANE RET MEBANE NC	DIST	44.00	2.40	
24	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
25	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
26	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
27	MEBANE RET MEBANE NC	DIST	44.00	6.90	2.40
28	MEBANE RET MEBANE NC	DIST	44.00	13.00	
29	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
30	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
31	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
32	MEBANE TIE MEBANE NC	TRANS	100.00	44.00	
33	MEBANE TIE MEBANE NC	TRANS	24.00	0.20	
34	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
35	MERRITT DR RET GREENSBORO NC	DIST	100.00	24.00	
36	MIDWAY SS UNION SC	TRANS	100.00	33.00	
37	MIDWAY SS UNION SC	TRANS	100.00	33.00	
38	MILLER HILL RET LENOIR NC	DIST		240.00	
39	MILLER HILL RET LENOIR NC	DIST		240.00	
40	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
2	MILLER HILL RET LENOIR NC	DIST	100.00	13.00	
3	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
4	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
5	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
6	MILLER HILL TIE LENOIR NC	TRANS	100.00	44.00	
7	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
8	MILLERS CREEK RET NORTH WILKESBORO NC	DIST	100.00	13.00	
9	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
10	MILLIS RET HIGH POINT NC	DIST	100.00	24.00	
11	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
12	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
13	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
14	MILLS RIVER RET HENDERSONVILLE NC	DIST	121.00	6.90	13.00
15	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
16	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
17	MINE SHAFT RET CHARLOTTE NC	DIST	100.00	24.00	
18	MINI RANCH RET WAXHAW NC	DIST	100.00	24.00	
19	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
20	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
21	MITCHELL RIVER TIE ELKIN NC	TRANS	230.00	100.00	44.00
22	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
23	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00		
24	MITCHELL RIVER TIE ELKIN NC	TRANS	44.00	0.40	
25	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
26	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
27	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
28	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	6.90	2.40
29	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
30	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
31	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	44.00	
32	MOCKSVILLE MN MOCKSVILLE NC	TRANS	24.00	0.20	
33	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
34	MOCKSVILLE MN MOCKSVILLE NC	TRANS	100.00	24.00	
35	MOCKSVILLE SOLAR	TRANS	44.00		
36	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
37	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
38	MONROE MN MONROE NC	TRANS	44.00	6.90	2.40
39	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
40	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90

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1	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
2	MONROE MN MONROE NC	TRANS	100.00	13.00	6.90
3	MONROE MN MONROE NC	TRANS	100.00	44.00	
4	MONROE MN MONROE NC	TRANS	100.00	44.00	
5	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
6	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
7	MONROE RD RET CHARLOTTE NC	DIST	100.00	13.00	
8	MONROETON RET MONROETON NC	DIST	44.00	13.00	
9	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
10	MONTCLAIRE RET CHARLOTTE NC	DIST	100.00	24.00	
11	MONTICELLO RET GREENSBORO NC	DIST	44.00	13.00	
12	MONTROYAL RD RET RURAL HALL NC	DIST	100.00	13.00	
13	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
14	MOONVILLE RET GREENVILLE SC	DIST	100.00	13.00	
15	MOORE RET MOORE SC	DIST	44.00	13.00	
16	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
17	MOORESBORO RET MOORESBORO NC	DIST	44.00	13.00	
18	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
19	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
20	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
21	MOORESVILLE TIE MOORESVILLE NC	TRANS	100.00	44.00	
22	MOORESVILLE TIE MOORESVILLE NC	TRANS	24.00	0.20	
23	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
24	MORGANTON CITY DEL 3 MORGANTON NC	DIST	44.00	13.00	
25	MORGANTON CITY DEL 4 MATS MORGANTON NC	DIST	100.00	13.00	
26	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
27	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
28	MORGANTON TIE MORGANTON NC	TRANS	100.00	24.00	13.00
29	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
30	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
31	MORGANTON TIE MORGANTON NC	TRANS	100.00	44.00	
32	MORGANTON TIE MORGANTON NC	TRANS			
33	MORGANTON TIE MORGANTON NC	TRANS			
34	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
35	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
36	MORNING STAR TIE MATTHEWS NC	TRANS	230.00	100.00	44.00
37	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	
38	MORNING STAR TIE MATTHEWS NC	TRANS	100.00	24.00	
39	MORNING STAR TIE MATTHEWS NC	TRANS	44.00	0.40	
40	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	

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1	MOTLEY TIE EDEN NC	TRANS	100.00	44.00	
2	MOTLEY TIE EDEN NC	TRANS	24.00	0.20	
3	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
4	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
5	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
6	MT AIRY RET MT AIRY NC	DIST	100.00	6.90	2.40
7	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
8	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
9	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
10	MT AIRY RET MT AIRY NC	DIST	100.00	13.00	6.90
11	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
12	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
13	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
14	MT HOPE CHURCH RD RET GREENSBORO NC	DIST	100.00	6.90	2.40
15	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
16	MT OLIVE RET CONOVER NC	DIST	44.00	13.00	
17	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
18	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
19	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
20	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
21	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
22	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	6.90	2.40
23	MT PLEASANT RET MOUNT PLEASANT NC	DIST	44.00	13.00	4.10
24	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
25	MT TABOR RET WINSTON-SALEM NC	DIST	100.00	13.00	
26	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	
27	MTN VIEW RET HICKORY NC	DIST	100.00	13.00	
28	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
29	MUD CREEK RD RET BOILING SPRINGS SC	DIST	100.00	13.00	
30	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
31	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
32	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
33	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	
34	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
35	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
36	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
37	MULBERRY CREEK RET WARE SHOALS SC	DIST	100.00	6.90	2.40
38	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	
39	MURDOCK RD RET TROUTMAN NC	DIST	44.00	13.00	
40	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40

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1	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
2	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
3	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
4	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
5	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
6	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	13.00	6.90
7	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
8	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
9	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
10	N CHARLOTTE RET CHARLOTTE NC	DIST	100.00	6.90	2.40
11	N FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
12	N GORDONTON RET THOMASVILLE NC	DIST	100.00	13.00	
13	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
14	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
15	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	13.00
16	N GREENSBORO TIE GREENSBORO NC	TRANS	100.00	44.00	
17	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00		
18	N GREENSBORO TIE GREENSBORO NC	TRANS	230.00	100.00	44.00
19	N GREENSBORO TIE GREENSBORO NC	TRANS	44.00	0.40	
20	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
21	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
22	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
23	N GREENVILLE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
24	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
25	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00		
26	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
27	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
28	N GREENVILLE TIE GREENVILLE SC	TRANS	44.00	2.40	0.60
29	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
30	N GREENWOOD RET GREENWOOD SC	DIST	44.00	13.00	
31	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
32	N HICKORY RET HICKORY NC	DIST	100.00	13.00	
33	N STANLEY RET STANLEY NC	DIST	100.00	13.00	4.10
34	N STANLEY RET STANLEY NC	DIST	100.00	13.00	
35	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
36	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
37	N WINSTON RET WINSTON-SALEM NC	DIST	100.00	13.00	
38	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	
39	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	13.00	
40	NANTAHALA HYDRO TOPTON NC	TRANS	161.00	34.50	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
2	NANTAHALA HYDRO TOPTON NC	TRANS	13.00	0.40	
3	NANTAHALA HYDRO TOPTON NC	TRANS	34.50	13.00	
4	NAPLES RET NAPLES NC	DIST	44.00	13.00	
5	NAPLES RET NAPLES NC	DIST	44.00	13.00	
6	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
7	NEALS CREEK RET ANDERSON SC	DIST	44.00	13.00	
8	NEBO RET MARION NC	DIST	100.00	13.00	
9	NELSON RET DURHAM NC	DIST	100.00	24.00	
10	NELSON RET DURHAM NC	DIST	100.00	24.00	
11	NEW CUT RD RET INMAN SC	DIST	100.00	13.00	
12	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
13	NEW HOPE RET GASTONIA NC	DIST	100.00	13.00	
14	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
15	NEWBERRY MN NEWBERRY SC	TRANS	100.00	24.00	
16	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
17	NEWELL RET CHARLOTTE NC	DIST	100.00	24.00	
18	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
19	NEWPORT RET NEWPORT SC	DIST	44.00	13.00	
20	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
21	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
22	NEWPORT TIE NEWPORT SC	TRANS	230.00	100.00	44.00
23	NEWPORT TIE NEWPORT SC	TRANS	44.00	0.40	
24	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
25	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
26	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
27	NEWPORT TIE NEWPORT SC	TRANS	500.00	230.00	24.00
28	NEWPORT TIE NEWPORT SC	TRANS	44.00		
29	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
30	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
31	NEWTON CITY DEL 2 NEWTON NC	DIST	100.00	13.00	6.90
32	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
33	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
34	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
35	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
36	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
37	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
38	NEWTON TIE NEWTON NC	TRANS	100.00	24.00	
39	NEWTON TIE NEWTON NC	TRANS	24.00	0.20	
40	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
2	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
3	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
4	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
5	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
6	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
7	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
8	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
9	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	44.00	2.40	
10	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
11	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
12	NINETY-NINE ISLANDS HYDRO BLACKSBURG SC	TRANS	24.00	0.20	
13	NIX RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
14	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
15	NORRIS RET CATEECHEE SC	DIST	44.00	13.00	
16	NORTH DENVER RET DENVER NC	DIST	100.00	13.00	
17	NORTH LAKES RET HICKORY NC	DIST	100.00	13.00	
18	NORTH LINCOLN RET LINCOLNTON NC	DIST	44.00	13.00	
19	NORTH ST RET ANDERSON SC	DIST	44.00	13.00	
20	OAK GROVE RET SHELBY NC	DIST	44.00	13.00	8.00
21	OAK GROVE RET SHELBY NC	DIST	44.00	13.00	
22	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	
23	OAK RIDGE RET KERNERSVILLE NC	DIST	100.00	13.00	
24	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
25	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
26	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
27	OAKBORO RET OAKBORO NC	DIST	100.00	13.00	6.90
28	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
29	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
30	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
31	OAKBORO TIE OAKBORO NC	TRANS	230.00	100.00	44.00
32	OAKBORO TIE OAKBORO NC	TRANS	44.00		
33	OAKBORO TIE OAKBORO NC	TRANS	44.00	0.48	
34	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
35	OAKLAND RD RET SPINDALE NC	DIST	100.00	13.00	
36	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
37	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
38	OAKVALE TIE GREENVILLE SC	TRANS	100.00	24.00	
39	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
40	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
2	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	24.00
3	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
4	OAKVALE TIE GREENVILLE SC	TRANS	100.00	13.00	
5	OAKVALE TIE GREENVILLE SC	TRANS	100.00	44.00	
6	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
7	OAKWOOD ST RET MEBANE NC	DIST	100.00	13.00	
8	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	230.00	4.10	
9	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	24.00	4.10	
10	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	525.00	240.00	
11	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	230.00	4.10	
12	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
13	OCONEE 230KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
14	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
15	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
16	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
17	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	500.00	230.00	24.00
18	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
19	OCONEE 525KV SWITCHYARD NEWRY SC	TRANS	4.10	0.40	
20	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	24.00	
21	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	24.00	6.90	4.10
22	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
23	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
24	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
25	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
26	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
27	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
28	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
29	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
30	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
31	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
32	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
33	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10
34	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	230.00	6.90	4.10
35	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
36	OCONEE NUCLEAR STA UNIT 1 NEWRY SC	TRANS	4.10	0.60	
37	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	24.00	
38	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	24.00	6.90	4.10
39	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
40	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	

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SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
2	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
3	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
4	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
5	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
6	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
7	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	4.10	0.60	
8	OCONEE NUCLEAR STA UNIT 2 NEWRY SC	TRANS	230.00	6.90	4.10
9	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
10	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
11	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
12	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	500.00	24.00	
13	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	24.00	6.90	4.10
14	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
15	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
16	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
17	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
18	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
19	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
20	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
21	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
22	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	4.10	0.60	
23	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	230.00	6.90	4.10
24	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
25	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	13.00	4.10	
26	OCONEE NUCLEAR STA UNIT 3 NEWRY SC	TRANS	100.00	4.10	4.10
27	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
28	OCONEE SITE 100KV NEWRY SC	TRANS	100.00	24.00	
29	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
30	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
31	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
32	OGBURN DIST STOKESDALE NC	DIST	44.00	24.00	6.90
33	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
34	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
35	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
36	OLD FORT RET OLD FORT NC	DIST	44.00	6.90	2.40
37	OLD FORT RET OLD FORT NC	DIST	44.00	13.00	
38	ONEAL RET GREER SC	DIST	100.00	13.00	
39	ONEAL RET GREER SC	DIST	100.00	13.00	
40	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
2	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
3	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	2.40
4	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
5	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
6	OSSIPEE DIST OSSIPEE NC	DIST	24.00	6.90	
7	OTTO RET OTTO NC	DIST	69.00	13.00	
8	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
9	OXFORD HYDRO CONOVER NC	TRANS	100.00	6.90	
10	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
11	OXFORD RD RET DURHAM NC	DIST	100.00	13.00	
12	OYAMA RET HICKORY NC	DIST	100.00	13.00	
13	OYAMA RET HICKORY NC	DIST	100.00	13.00	
14	PACOLET RET PACOLET SC	DIST	44.00	6.90	
15	PACOLET RET PACOLET SC	DIST	44.00	6.90	
16	PACOLET RET PACOLET SC	DIST	44.00	6.90	
17	PACOLET RET PACOLET SC	DIST	44.00	6.90	
18	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	13.00
19	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	13.00
20	PACOLET TIE PACOLET SC	TRANS	230.00	100.00	44.00
21	PANORAMA RET GREENWOOD SC	DIST	44.00	13.00	
22	PARADISE RET FOREST CITY NC	DIST	44.00	13.00	
23	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
24	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
25	PARK RD RET CHARLOTTE NC	DIST	100.00	13.00	
26	PARKWAY SS GROVER NC	DIST	100.00	13.00	
27	PARKWAY SS GROVER NC	DIST	100.00	13.00	
28	PARKWOOD RET DURHAM NC	DIST	100.00	24.00	
29	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
30	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
31	PARKWOOD TIE DURHAM NC	TRANS	230.00	100.00	44.00
32	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
33	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
34	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
35	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
36	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
37	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
38	PARKWOOD TIE DURHAM NC	TRANS	500.00	230.00	13.00
39	PARKWOOD TIE DURHAM NC	TRANS	44.00	0.40	
40	PARKWOOD TIE DURHAM NC	TRANS	13.00	0.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
2	PATTERSON SPRINGS RET SHELBY NC	DIST	100.00	13.00	
3	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
4	PEACE HAVEN RD RET CLEMMONS NC	DIST	100.00	13.00	
5	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
6	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
7	PEACH VALLEY TIE SPARTANBURG SC	TRANS	230.00	100.00	44.00
8	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
9	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00		
10	PEACH VALLEY TIE SPARTANBURG SC	TRANS	44.00	0.40	
11	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
12	PEACOCK TIE GASTONIA NC	TRANS	230.00	100.00	44.00
13	PEACOCK TIE GASTONIA NC	TRANS	100.00	13.00	
14	PEACOCK TIE GASTONIA NC	TRANS	44.00		
15	PEACOCK TIE GASTONIA NC	TRANS	44.00	0.40	
16	PEACOCK TIE GASTONIA NC	TRANS	44.00		
17	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
18	PEARMAN SS ANDERSON SC	DIST	100.00	13.00	
19	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	
20	PEBBLE CREEK RET GREENVILLE SC	DIST	100.00	13.00	
21	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
22	PEELER RET GAFFNEY SC	DIST	44.00	13.00	
23	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
24	PELHAM RET TAYLORS SC	DIST	100.00	24.00	
25	PELZER RET PELZER SC	DIST	44.00	13.00	
26	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
27	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
28	PENDLETON RET PENDLETON SC	DIST	44.00	2.40	
29	PENDLETON RET PENDLETON SC	DIST	44.00	6.90	2.40
30	PENDLETON RET PENDLETON SC	DIST	44.00	13.00	
31	PERTH RD RET TROUTMAN NC	DIST	44.00	24.00	
32	PERTH RD RET TROUTMAN NC	DIST	44.00	13.00	
33	PETERS CREEK RET SPARTANBURG SC	DIST	44.00	13.00	
34	PFAFFTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
35	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
36	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
37	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
38	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
39	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
40	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PICKENS RET PICKENS SC	DIST	44.00	6.90	2.40
2	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
3	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
4	PICKENS TIE PICKENS SC	TRANS	100.00	44.00	
5	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
6	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
7	PIEDMONT RET PIEDMONT SC	DIST	44.00	13.00	6.90
8	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
9	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
10	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
11	PIEDMONT RET PIEDMONT SC	DIST	44.00	6.90	2.40
12	PIEDMONT RET PIEDMONT SC	DIST	13.00	2.40	
13	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
14	PIERCETOWN SS ANDERSON SC	DIST	100.00	13.00	
15	PINCH GUT CREEK RET NEWTON NC	DIST	100.00	13.00	
16	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
17	PINEWOOD RET SPARTANBURG SC	DIST	100.00	13.00	
18	PINK HARRILL TIE CAROLEEN NC	TRANS	100.00	44.00	
19	PINK HARRILL TIE CAROLEEN NC	TRANS	100.00	44.00	
20	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
21	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
22	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
23	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
24	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
25	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
26	PINNACLE TIE PINNACLE NC	TRANS	100.00	44.00	
27	PINNACLE TIE PINNACLE NC	TRANS	24.00	0.20	
28	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
29	PIONEER AVE RET CHARLOTTE NC	DIST	100.00	24.00	
30	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
31	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
32	PIPER GLEN RET CHARLOTTE NC	DIST	100.00	24.00	
33	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
34	PISGAH TIE PISGAH FOREST NC	TRANS	230.00	100.00	44.00
35	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	44.00	
36	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
37	PISGAH TIE PISGAH FOREST NC	TRANS	100.00	100.00	13.00
38	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
39	PISGAH TIE PISGAH FOREST NC	TRANS	44.00		
40	PISGAH TIE PISGAH FOREST NC	TRANS	44.00	0.40	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	PITTS SCHOOL RET CONCORD NC	DIST	100.00	13.00	
2	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
3	PLAINVIEW RET ANDERSON SC	DIST	100.00	13.00	
4	PLATO LEE RET SHELBY NC	DIST	100.00	12.47	
5	PLEASANT GARDEN RET PLEASANT GARDEN NC	DIST	44.00	13.00	
6	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
7	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
8	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	230.00	100.00	44.00
9	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
10	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
11	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
12	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00	230.00	24.00
13	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00		
14	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	500.00		
15	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	44.00	0.40	
16	PLEASANT GARDEN TIE PLEASANT GARDEN NC	TRANS	24.00	0.40	
17	POPE RD RET DURHAM NC	DIST	100.00	24.00	
18	POPE RD RET DURHAM NC	DIST	100.00	24.00	
19	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
20	POPLAR TENT RET CONCORD NC	DIST	100.00	13.00	
21	PORTER RANCH RET VAN WYCK SC	DIST	446.90	2.40	
22	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
23	PORTER RANCH RET VAN WYCK SC	DIST	44.00	13.00	
24	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
25	PORTER RANCH RET VAN WYCK SC	DIST	44.00	6.90	2.40
26	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
27	POWDERSVILLE RET POWDERSVILLE SC	DIST	44.00	13.00	
28	PROCTER & GAMBLE GBORO PL T&D GREENSBORO NC	DIST	44.00	13.00	
29	PROPST RET HICKORY NC	DIST	44.00	13.00	
30	PROPST RET HICKORY NC	DIST	44.00	13.00	
31	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
32	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
33	PROVOL RET CHARLOTTE NC	DIST	100.00	24.00	
34	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	
35	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	13.00	
36	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
37	PUTMAN RET FOUNTAIN INN SC	DIST	100.00	24.00	
38	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
39	RAGSDALE RET JAMESTOWN NC	DIST	100.00	24.00	
40	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	4.10

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	RANDLEMAN RD RET RANDLEMAN NC	DIST	100.00	13.00	
2	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
3	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
4	RANDOLPH AVE RET GREENSBORO NC	DIST	100.00	24.00	
5	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
6	RANKIN AVE RET MOUNT HOLLY NC	DIST	100.00	13.00	
7	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
8	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
9	REAMES RD RET CHARLOTTE NC	DIST	100.00	24.00	
10	RED RAIDER RET BELMONT NC	DIST	100.00	13.00	
11	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
12	RED ROSE RET LANCASTER SC	DIST	100.00	13.00	
13	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
14	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
15	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
16	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	24.00	
17	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
18	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
19	REEDY RIVER TIE FOUNTAIN INN SC	TRANS	100.00	44.00	24.00
20	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
21	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	
22	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
23	REIDSVILLE RET REIDSVILLE NC	DIST	100.00	13.00	4.10
24	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
25	REMOUNT RD RET CHARLOTTE NC	DIST	100.00	13.00	
26	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
27	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
28	RESEARCH TRIANGLE RET DURHAM NC	DIST	100.00	24.00	
29	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
30	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
31	RHODHISS HYDRO PL RHODHISS NC	TRANS	46.00	6.60	
32	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
33	RHODHISS TIE RHODHISS NC	TRANS	100.00	44.00	
34	RHODHISS TIE RHODHISS NC	TRANS	44.00	0.24	
35	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	
36	RICH MOUNTAIN RET BREVARD NC	DIST	100.00	13.00	
37	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
38	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
39	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90
40	RICHFIELD RET RICHFIELD NC	DIST	100.00	13.00	6.90

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
2	RIDGEVIEW RET EDEN NC	DIST	100.00	13.00	
3	RITTERS LAKE RD RET GREENSBORO NC	TRANS	100.00	24.94	
4	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
5	RIVER HILLS RET CLOVER SC	DIST	100.00	24.00	
6	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	230.00	100.00	44.00
7	RIVERBEND STEAM STA MOUNT HOLLY NC	TRANS	230.00	100.00	44.00
8	RIVERSTONE RET FOREST CITY NC	DIST	100.00	13.00	
9	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
10	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
11	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
12	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	161.00	13.00	
13	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00	34.50	
14	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
15	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
16	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
17	ROBBINSVILLE RET ROBBINSVILLE NC	DIST	13.00		
18	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
19	ROBERTA RD RET CONCORD NC	DIST	44.00	13.00	
20	ROCHESTER TIE NEWRY SC	TRANS	100.00	44.00	
21	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
22	ROCK HILL CITY DEL 4 ROCK HILL SC	DIST	100.00	24.00	13.00
23	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
24	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
25	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
26	ROCK HILL MN ROCK HILL SC	DIST	100.00	13.00	6.90
27	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
28	ROCKETT RET CONOVER NC	DIST	100.00	13.00	
29	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
30	ROCKWELL RET ROCKWELL NC	DIST	100.00	13.00	
31	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
32	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
33	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
34	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	44.00	4.10	
35	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
36	ROCKY CREEK HYDRO GREAT FALLS SC	TRANS	2.40	0.40	
37	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
38	ROPER MTN RET GREENVILLE SC	DIST	100.00	13.00	
39	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
40	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90

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1	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
2	ROSE HILL RET GAFFNEY SC	DIST	100.00	13.00	6.90
3	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
4	ROSMAN SS ROSMAN NC	DIST	44.00	12.47	
5	ROSMAN SS ROSMAN NC	DIST	44.00	12.47	
6	ROSMAN SS ROSMAN NC	DIST	44.00	6.90	2.40
7	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
8	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
9	ROSMAN SS ROSMAN NC	DIST	44.00	13.00	6.90
10	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	44.00	13.00	
11	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
12	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
13	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
14	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
15	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
16	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
17	ROUGHEDGE TIE ROUGHEDGE NC	TRANS	100.00	44.00	
18	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
19	ROYAL RET CHARLOTTE NC	DIST	100.00	24.00	
20	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	
21	ROZZELLES RET CHARLOTTE NC	DIST	100.00	13.00	
22	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
23	RUDD RET GREENSBORO NC	DIST	100.00	24.00	
24	RUFFIN RET RUFFIN NC	DIST	44.00	13.00	
25	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
26	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
27	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
28	RUFFIN RET RUFFIN NC	DIST	44.00	6.90	
29	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
30	RURAL HALL RET RURAL HALL NC	DIST	44.00	13.00	
31	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
32	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
33	RURAL HALL TIE RURAL HALL NC	TRANS	230.00	100.00	44.00
34	RURAL HALL TIE RURAL HALL NC	TRANS	44.00	0.40	
35	RURAL HALL TIE RURAL HALL NC	TRANS	44.00		
36	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	24.00	13.00
37	RUTHERFORD COLLEGE RET RUTHERFORD COLLEGE	DIST	44.00	13.00	
38	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
39	RUTLEDGE TIE MT AIRY NC	TRANS	100.00	44.00	
40	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	

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1	S CULLOWHEE RET CULLOWHEE NC	DIST	66.00	13.00	
2	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
3	S FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
4	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
5	S GASTONIA RET GASTONIA NC	DIST	44.00	13.00	
6	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
7	S HICKORY RET HICKORY NC	DIST	100.00	13.00	
8	S SHELBY SS SHELBY NC	DIST	44.00	13.00	
9	S SYLVA RET SYLVA NC	DIST	67.00	13.20	
10	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
11	SADLER TIE REIDSVILLE NC	TRANS	230.00	100.00	44.00
12	SADLER TIE REIDSVILLE NC	TRANS	44.00		
13	SADLER TIE REIDSVILLE NC	TRANS	44.00	0.40	
14	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
15	SALISBURY MN SALISBURY NC	TRANS	100.00	13.00	
16	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
17	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
18	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	
19	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
20	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
21	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
22	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
23	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
24	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
25	SALISBURY MN SALISBURY NC	TRANS	100.00	44.00	24.00
26	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
27	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
28	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
29	SALISBURY MN SALISBURY NC	TRANS	100.00	6.90	2.40
30	SALISBURY MN SALISBURY NC	TRANS	24.00	0.20	
31	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
32	SALUDA RET SALUDA NC	DIST	44.00	6.90	
33	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
34	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
35	SALUDA RET SALUDA NC	DIST	44.00	6.90	2.40
36	SALUDA RET SALUDA NC	DIST	44.00	6.90	
37	SALUDA RET SALUDA NC	DIST	44.00	6.90	
38	SANDS RD RET REIDSVILLE NC	DIST	100.00	24.00	
39	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
40	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
2	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	13.00	6.90
3	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
4	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
5	SANDY SPRINGS RET PENDLETON SC	DIST	44.00	6.90	2.40
6	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
7	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	100.00	44.00	
8	SANDY SPRINGS TIE SANDY SPRINGS SC	TRANS	24.00	0.20	
9	SAPPHIRE RET CASHIERS NC	DIST	66.00	13.00	
10	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
11	SAWMILLS RET SAWMILLS NC	DIST	44.00	13.00	
12	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
13	SAXAPAHAW RET SAXAPAHAW NC	DIST	44.00	13.00	
14	SCUFFLETOWN RET SIMPSONVILLE SC	DIST	100.00	13.00	
15	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
16	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	13.00	
17	SEDGE GARDEN RET KERNERSVILLE NC	DIST	100.00	24.00	
18	SENECA CITY DEL 1 SENECA SC	DIST	100.00	13.00	
19	SENECA CITY DEL 2 SENECA SC	DIST	100.00	13.00	
20	SENECA TIE SENECA SC	TRANS	100.00	44.00	
21	SENECA TIE SENECA SC	TRANS	100.00	44.00	
22	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
23	SEVENTH ST RET BURLINGTON NC	DIST	100.00	24.00	
24	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
25	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
26	SEVENTH ST RET BURLINGTON NC	DIST	24.00	6.90	2.40
27	SEVENTH ST RET BURLINGTON NC	DIST	24.00	2.40	
28	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	
29	SEWARD RET WINSTON-SALEM NC	DIST	100.00	24.00	
30	SHACKTOWN RET YADKINVILLE NC	DIST	100.00	13.00	
31	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
32	SHADY GROVE TIE GREENVILLE SC	TRANS	230.00	100.00	44.00
33	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
34	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00		
35	SHADY GROVE TIE GREENVILLE SC	TRANS	44.00	0.40	
36	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
37	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
38	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
39	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
40	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
2	SHARON GROVE SS HICKORY GROVE SC	DIST	44.00	6.90	2.40
3	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
4	SHARON RET CHARLOTTE NC	DIST	100.00	24.00	
5	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
6	SHATTALON SW STA WINSTON-SALEM NC	TRANS	100.00	13.00	
7	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
8	SHELBY CITY DEL 8 SHELBY NC	DIST	44.00	13.00	
9	SHELBY MN SHELBY NC	DIST	44.00	2.40	
10	SHELBY MN SHELBY NC	DIST	44.00	2.40	
11	SHELBY MN SHELBY NC	DIST	44.00	2.40	
12	SHELBY MN SHELBY NC	DIST	44.00	2.40	
13	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
14	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
15	SHELBY TIE SHELBY NC	TRANS	230.00	100.00	44.00
16	SHELBY TIE SHELBY NC	TRANS	44.00		
17	SHELBY TIE SHELBY NC	TRANS	44.00		
18	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
19	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
20	SHELBY TIE SHELBY NC	TRANS	44.00	2.40	0.60
21	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
22	SHERRILLS FORD SS SHERRILLS FORD NC	DIST	44.00	13.00	
23	SHOPTON RET CHARLOTTE NC	DIST	100.00	24.00	
24	SHORTOFF RET HIGHLANDS NC	DIST	66.00	13.00	
25	SIX MILE RET SIX MILE SC	DIST	44.00	13.00	
26	SMITHTOWN RET SMITHTOWN NC	DIST	44.00	13.00	
27	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	24.00	
28	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	24.00	
29	SOUTHBOUND RET WINSTON-SALEM NC	DIST	100.00	13.00	
30	SOUTHPORT RD RET SPARTANBURG SC	DIST	100.00	13.00	
31	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
32	SPARTAN GREEN RET DUNCAN SC	DIST	100.00	24.00	
33	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
34	SPARTAN HEIGHTS RET HENDERSONVILLE NC	DIST	44.00	13.00	
35	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
36	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
37	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
38	SPEEDWAY RET HARRISBURG NC	DIST	100.00	13.00	6.90
39	SPEEDWAY RET HARRISBURG NC	DIST	100.00	24.00	
40	SPEEDWAY RET HARRISBURG NC	DIST	13.00		

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
2	SPRINGFIELD RET CHARLOTTE NC	DIST	100.00	24.00	
3	SPRINGS IND SS FORT LAWN SC	DIST	100.00	24.00	13.00
4	SPRINGS IND SS FORT LAWN SC	DIST	13.00		
5	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
6	ST MARKS RET BURLINGTON NC	DIST	100.00	24.00	
7	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
8	ST STEPHENS RET HICKORY NC	DIST	100.00	13.00	
9	STALLINGS RD RET DURHAM NC	DIST	100.00	13.00	
10	STALLINGS RD RET DURHAM NC	DIST	100.00	24.00	
11	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
12	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	13.00
13	STAMEY TIE STATESVILLE NC	TRANS	230.00	100.00	44.00
14	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
15	STAMEY TIE STATESVILLE NC	TRANS	13.00	0.40	
16	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
17	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
18	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
19	STARMOUNT FOREST DIST GREENSBORO NC	DIST	24.00	6.90	2.40
20	STARTOWN RET NEWTON NC	DIST	44.00	13.00	
21	STARTOWN RET NEWTON NC	DIST	44.00	13.00	
22	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	
23	STATESVILLE CITY DEL 2 STATESVILLE NC	DIST	100.00	24.00	13.00
24	STATESVILLE CITY DEL 3 STATESVILLE NC	DIST	100.00	24.00	
25	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
26	STATESVILLE RD RET SALISBURY NC	DIST	100.00	13.00	
27	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
28	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
29	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	44.00	
30	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
31	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
32	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
33	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
34	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
35	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
36	STATESVILLE TIE STATESVILLE NC	TRANS	100.00	13.00	6.90
37	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
38	STEELE CREEK RET CHARLOTTE NC	DIST	100.00	24.00	
39	STOUTS RET STOUTS NC	DIST	100.00	24.00	
40	STOUTS RET STOUTS NC	DIST	100.00	24.00	

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	STOUTS RET STOUTS NC	DIST	100.00	24.00	
2	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
3	SUGAR HILL TIE MARION NC	TRANS	100.00	44.00	
4	SUGAR HILL TIE MARION NC	TRANS	24.00	0.20	
5	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
6	SUMMERFIELD RET SUMMERFIELD NC	DIST	100.00	24.00	
7	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
8	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
9	SUMMEY ST RET CLEMSON SC	DIST	100.00	13.00	
10	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
11	SUMNER RET SALISBURY NC	DIST	100.00	13.00	
12	SUN CITY YORK SC	DIST	100.00	24.00	
13	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
14	SUNSET RET CHARLOTTE NC	DIST	100.00	13.00	
15	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
16	SWAIMTOWN RET WINSTON-SALEM NC	DIST	100.00	13.00	
17	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
18	SWAIN TIE BRYSON CITY NC	TRANS	161.00	66.00	
19	SWAIN TIE BRYSON CITY NC	TRANS	170.00	66.00	
20	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	
21	SWAIN TIE BRYSON CITY NC	TRANS	69.00	13.00	
22	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
23	SWEETWATER RET HICKORY NC	DIST	100.00	13.00	
24	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
25	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	100.00	44.00	
26	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
27	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	44.00	13.00	
28	SWEPSONVILLE TIE SWEPSONVILLE NC	TRANS	24.00	0.20	
29	TABERNACLE CHURCH RET GREENSBORO NC	DIST	44.00	13.00	
30	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
31	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	
32	TABLE ROCK TIE MORGANTON NC	TRANS	100.00	44.00	33.00
33	TABLE ROCK TIE MORGANTON NC	TRANS	44.00		
34	TABLE ROCK TIE MORGANTON NC	TRANS	24.00	0.20	
35	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
36	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
37	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
38	TANNER RET RUTHERFORDTON NC	DIST	100.00	6.90	2.40
39	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	
40	TARRANT RD RET GREENSBORO NC	DIST	100.00	24.00	

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
2	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	44.00	
3	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
4	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
5	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
6	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	24.00	0.20	
7	TAYLORSVILLE TIE TAYLORSVILLE NC	TRANS	100.00	13.00	6.90
8	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
9	TECHNOLOGY RET CHARLOTTE NC	DIST	100.00	24.00	
10	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	
11	TEGA CAY RET FORT MILL SC	DIST	100.00	24.00	13.00
12	TENNESSEE CREEK HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
13	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
14	THIRD AVE RET HICKORY NC	DIST	100.00	13.00	
15	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
16	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
17	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
18	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
19	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
20	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
21	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
22	THOMASVILLE MN THOMASVILLE NC	DIST	100.00	6.90	2.40
23	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
24	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
25	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
26	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	6.90	
27	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	66.00	
28	THORPE HYDRO TUCKASEGEE NC	TRANS	161.00	66.00	
29	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	13.00	
30	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
31	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
32	THORPE HYDRO TUCKASEGEE NC	TRANS	66.00	4.10	
33	THORPE HYDRO TUCKASEGEE NC	TRANS	6.90		
34	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
35	THRIFT RET CHARLOTTE NC	DIST	100.00	13.00	
36	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
37	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
38	TIGER TIE DUNCAN SC	TRANS	230.00	100.00	44.00
39	TIGER TIE DUNCAN SC	TRANS	44.00		
40	TIGER TIE DUNCAN SC	TRANS	44.00		

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1	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
2	TIGER TIE DUNCAN SC	TRANS	44.00	0.40	
3	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
4	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
5	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
6	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
7	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
8	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
9	TIGERVILLE RET TIGERVILLE SC	DIST	44.00	6.90	2.40
10	TNS M GREEN PL STA 3 GREER SC	DIST	100.00	13.00	
11	TOAST RET TOAST NC	DIST	100.00	13.00	
12	TOAST RET TOAST NC	DIST	100.00	13.00	
13	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
14	TOXAWAY TIE ANDERSON SC	TRANS	100.00	44.00	24.00
15	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
16	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
17	TOXAWAY TIE ANDERSON SC	TRANS	100.00	13.00	
18	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
19	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
20	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
21	TOXAWAY TIE ANDERSON SC	TRANS	44.00	2.40	
22	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
23	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
24	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
25	TRADESVILLE RET TRADESVILLE SC	DIST	44.00	6.90	
26	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
27	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
28	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
29	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
30	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
31	TRAVELERS REST RET TRAVELERS REST SC	DIST	44.00	6.90	2.40
32	TREMONT RET LENOIR NC	DIST	44.00	13.00	
33	TREMONT RET LENOIR NC	DIST	44.00	13.00	
34	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
35	TREYBURN RET DURHAM NC	DIST	100.00	24.00	
36	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
37	TRIAD PARK RET KERNERSVILLE NC	DIST	100.00	13.00	
38	TRIANGLE RET LOWESVILLE NC	DIST	100.00	24.00	
39	TRIANGLE RET LOWESVILLE NC	DIST	100.00	13.00	4.10
40	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation	Character of Substation	VOLTAGE (In MVa)		
			Primary	Secondary	Tertiary
	(a)	(b)	(c)	(d)	(e)
1	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
2	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
3	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
4	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
5	TRIBBLE ST RET ANDERSON SC	DIST	44.00	2.40	0.60
6	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
7	TRIBBLE ST RET ANDERSON SC	DIST	44.00	6.90	2.40
8	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
9	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
10	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
11	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	6.90
12	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
13	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
14	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
15	TRINITY RIDGE RET LAURENS SC	DIST	44.00	6.90	2.40
16	TRINITY RIDGE RET LAURENS SC	DIST	44.00	13.00	
17	TRIPLETT RET MOORESVILLE NC	DIST	100.00	24.00	
18	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	
19	TRIPLETT RET MOORESVILLE NC	DIST	100.00	13.00	6.90
20	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	
21	TROLLINGWOOD RET HAW RIVER NC	DIST	100.00	24.00	
22	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
23	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
24	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
25	TROUTMAN RET TROUTMAN NC	DIST	44.00	6.90	2.40
26	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
27	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
28	TROUTMAN RET TROUTMAN NC	DIST	44.00	13.00	6.90
29	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
30	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
31	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
32	TRYON RET TRYON NC	DIST	44.00	6.90	2.40
33	TRYON RET TRYON NC	DIST	44.00	13.00	
34	TRYON RET TRYON NC	DIST	44.00	13.00	
35	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
36	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	230.00	161.00	13.00
37	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
38	TUCKASEGEE TIE TUCKASEGEE NC	TRANS	13.00	0.40	
39	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	
40	TUCKERS CREEK RET BREVARD NC	DIST	44.00	13.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	2.40
2	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	
3	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	
4	TUMBLING SHOALS SS LAURENS SC	DIST	44.00	6.90	2.40
5	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
6	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
7	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00	2.40	0.60
8	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	44.00		
9	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
10	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	2.40		
11	TURNER SHOALS SW STA MILL SPRINGS NC	TRANS	24.00	0.20	
12	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
13	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
14	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	6.90	
15	TURNERSBURG RET TURNERSBURG NC	DIST	44.00	24.00	6.90
16	TYSINGER RD RET MIDWAY NC	DIST	100.00	13.00	
17	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
18	UNA RET SPARTANBURG SC	DIST	100.00	13.00	
19	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
20	UNC-CH DEL 1 CAMERON CHAPEL HILL NC	DIST	100.00	13.00	
21	UNC-CH DEL 2 SOUTH CHAPEL HILL NC	DIST	100.00	13.00	
22	UNIFI MADISON T&D MADISON NC	DIST	100.00	24.00	
23	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
24	UNIFI YADKINVILLE T&D STA 1 YADKINVILLE NC	DIST	100.00	13.00	
25	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
26	UNIFI YADKINVILLE T&D STA 2 YADKINVILLE NC	DIST	100.00	24.00	
27	UNIV OF N C CHARLOTTE STA 2 CHARLOTTE NC	DIST	100.00	44.00	
28	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
29	UPWARD RD RET HENDERSONVILLE NC	DIST	100.00	13.00	
30	URQUHART STEAM STA AUGUSTA GA	TRANS	100.00	13.00	
31	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
32	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
33	VALDESE RET VALDESE NC	DIST	44.00	2.40	0.60
34	VALDESE RET VALDESE NC	DIST	44.00	13.00	
35	VALDESE RET VALDESE NC	DIST	44.00	13.00	
36	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
37	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
38	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
39	VALDESE TIE VALDESE NC	TRANS	100.00	24.00	
40	VALDESE TIE VALDESE NC	TRANS	100.00	44.00	

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SUBSTATIONS

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2. Substations which serve only one industrial or street railway customer should not be listed below.
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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
2	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
3	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
4	VALMEAD RET LENOIR NC	DIST	44.00	13.00	6.90
5	VALMEAD RET LENOIR NC	DIST	44.00	13.00	
6	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
7	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
8	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
9	VAN WYCK RET VAN WYCK SC	DIST	44.00	13.00	6.90
10	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
11	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
12	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
13	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	
14	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
15	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
16	VAN WYCK RET VAN WYCK SC	DIST	44.00	6.90	2.40
17	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
18	VAN WYCK TIE VAN WYCK SC	DIST	100.00	44.00	
19	VAN WYCK TIE VAN WYCK SC	DIST	24.00	0.20	
20	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
21	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
22	VANDALIA RET GREENSBORO NC	DIST	100.00	24.00	
23	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
24	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
25	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
26	VANDALIA RET GREENSBORO NC	DIST	24.00	6.90	2.40
27	VERDAE RET GREENVILLE SC	DIST	100.00	24.00	
28	VERDAE RET GREENVILLE SC	DIST	100.00	13.00	
29	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
30	VICTOR HILL SPARTANBURG SC	DIST	100.00	13.00	
31	VICTOR HILL SPARTANBURG SC	DIST	100.00	24.00	
32	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
33	W FRANKLIN RET FRANKLIN NC	DIST	66.00	13.00	
34	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	
35	W GASTONIA RET GASTONIA NC	DIST	100.00	13.00	
36	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
37	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
38	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
39	W HICKORY RET HICKORY NC	DIST	44.00	2.40	
40	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40

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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
2	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
3	W NORWOOD RET NORWOOD NC	DIST	24.00	6.90	2.40
4	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
5	W NORWOOD RET NORWOOD NC	DIST	100.00	24.00	
6	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
7	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
8	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
9	W SPARTANBURG TIE SPARTANBURG SC	TRANS	100.00	44.00	
10	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
11	WADDELL RD RET GREENVILLE SC	DIST	100.00	13.00	
12	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
13	WADSWORTH RET SPARTANBURG SC	DIST	100.00	13.00	
14	WALDEN RET SPARTANBURG SC	DIST	100.00	24.00	
15	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
16	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
17	WALHALLA TIE WALHALLA SC	TRANS	100.00	44.00	
18	WALHALLA TIE WALHALLA SC	TRANS	44.00	0.20	
19	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
20	WALKER TIE HARMONY SC	TRANS	100.00	44.00	
21	WALKER TIE HARMONY SC	TRANS	24.00	0.20	
22	WALKER TIE HARMONY SC	TRANS	24.00	0.20	
23	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
24	WALKERTOWN RET WALKERTOWN NC	DIST	100.00	13.00	
25	WALLACE RD RET MIDLAND NC	DIST	100.00	24.00	
26	WALNUT COVE TIE WALNUT COVE NC	TRANS	100.00	44.00	
27	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	13.00
28	WALNUT COVE TIE WALNUT COVE NC	TRANS	44.00	24.00	
29	WARE PLACE RET PELZER SC	DIST	44.00	6.90	
30	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
31	WARE PLACE RET PELZER SC	DIST	44.00	6.90	2.40
32	WARE PLACE RET PELZER SC	DIST	44.00	6.90	13.00
33	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
34	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
35	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
36	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	4.10
37	WASHBURN RET BOSTIC NC	DIST	44.00	13.00	
38	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
39	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
40	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	

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1	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
2	WATEREE HYDRO LUGOFF SC	TRANS	100.00	6.90	
3	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
4	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
5	WATEREE HYDRO LUGOFF SC	TRANS	6.90	0.60	
6	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
7	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
8	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	0.60
9	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
10	WATERTOWER RET KANNAPOLIS NC	DIST	13.00	2.40	
11	WATERTOWER RET KANNAPOLIS NC	DIST	44.00	13.00	
12	WAYNICK RD RET REIDSVILLE NC	DIST	100.00	13.00	
13	WEAVER RET DURHAM NC	DIST	100.00	24.00	
14	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
15	WEBBS CHAPEL RET DENVER NC	DIST	44.00	13.00	
16	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	
17	WEBSTER TIE WEBSTER NC	TRANS	161.00	66.00	
18	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
19	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
20	WEBSTER TIE WEBSTER NC	TRANS	66.00	13.00	
21	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
22	WENTWORTH RET WENTWORTH NC	DIST	100.00	13.00	
23	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
24	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
25	WESTMINSTER MN WESTMINSTER SC	DIST	100.00	44.00	
26	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
27	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
28	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
29	WESTMINSTER MN WESTMINSTER SC	DIST	44.00	6.90	2.40
30	WHITE CROSS RET WHITE CROSS NC	DIST	44.00	13.00	
31	WHITE PLAINS RET MT AIRY NC	DIST	100.00	13.00	
32	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
33	WHITEHALL RET ANDERSON SC	DIST	100.00	13.00	
34	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
35	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
36	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
37	WHITMIRE RET WHITMIRE SC	DIST	100.00	6.90	2.40
38	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
39	WHITSETT RET BURLINGTON NC	DIST	100.00	24.00	
40	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	

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1	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
2	WILDCAT TIE CORNELIUS NC	TRANS	100.00	44.00	
3	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
4	WILGROVE RET CHARLOTTE NC	DIST	100.00	24.00	
5	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
6	WILKES TIE NORTH WILKESBORO NC	TRANS	100.00	44.00	
7	WILKES TIE NORTH WILKESBORO NC	TRANS	24.00	0.20	
8	WILLARD RD RET WINSTON-SALEM NC	DIST	100.00	24.00	
9	WILLIAMSBURG RET REIDSVILLE NC	DIST	100.00	13.00	
10	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
11	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
12	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
13	WILLIAMSBURG TIE WILLIAMSBURG NC	TRANS	100.00	24.00	
14	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
15	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
16	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
17	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
18	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
19	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
20	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
21	WILLIAMSTON RET WILLIAMSTON SC	DIST	44.00	6.90	2.40
22	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
23	WILLOW CREEK RET HIGH POINT NC	DIST	100.00	13.00	
24	WINECOFF RET CONCORD NC	DIST	44.00	13.00	
25	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
26	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
27	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
28	WINECOFF TIE CONCORD NC	TRANS	230.00	100.00	44.00
29	WINECOFF TIE CONCORD NC	TRANS	44.00	0.40	
30	WINECOFF TIE CONCORD NC	TRANS	44.00		
31	WINECOFF TIE CONCORD NC	TRANS	44.00		
32	WINSTON TIE WINSTON-SALEM NC	TRANS	100.00	13.00	
33	WINTHROP UNIV DEL 3 ROCK HILL SC	DIST	24.00	13.00	
34	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
35	WITHERS RET CHARLOTTE NC	DIST	100.00	24.00	
36	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
37	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
38	WOODLAWN TIE CHARLOTTE NC	TRANS	100.00	13.00	
39	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
40	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	WOODLAWN TIE CHARLOTTE NC	TRANS	230.00	100.00	44.00
2	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00	0.40	
3	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
4	WOODLAWN TIE CHARLOTTE NC	TRANS	44.00		
5	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
6	WOODRUFF RET WOODRUFF SC	DIST	44.00	13.00	
7	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
8	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
9	WOODRUFF TIE WOODRUFF SC	TRANS	100.00	44.00	
10	WOODRUFF TIE WOODRUFF SC	TRANS	24.00	0.20	
11	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
12	WRENN RET PIEDMONT SC	DIST	100.00	13.00	
13	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
14	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
15	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
16	WYLIE HYDRO PL FORT MILL SC	TRANS	44.00	6.90	
17	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
18	WYLIE SW STA FORT MILL SC	TRANS	100.00	44.00	
19	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
20	WYNDWARD POINT RET NEWRY SC	DIST	100.00	24.00	
21	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
22	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
23	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
24	YADKINVILLE RET YADKINVILLE NC	DIST	100.00	6.90	2.40
25	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
26	YORK E C DEL 6 TIRZAH SC	DIST	44.00	13.00	
27	YORK E C DEL 9 HANCOCK SC	DIST	44.00	13.00	
28	YORK RET YORK SC	DIST	100.00	13.00	
29	YORK RET YORK SC	DIST	100.00	13.00	
30	YORK RET YORK SC	DIST	13.00	2.40	0.60
31	YORK RET YORK SC	DIST	13.00	2.40	0.60
32	YORK RET YORK SC	DIST	13.00	2.40	0.60
33	YORK RET YORK SC	DIST	100.00	24.00	13.00
34	ZF TRANSMISSIONS GVILLE LLC GRAY COURT SC	TRANS	100.00	13.00	
35	ZION CHURCH RD RET HICKORY NC	DIST	100.00	13.00	6.90
36	TOTAL		225554.96	54961.68	8330.10
37					
38	TRANSMISSION -				
39	GEORGIA	TRANS			
40	NORTH CAROLINA	TRANS			

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SUBSTATIONS

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4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SOUTH CAROLINA	TRANS			
2	TOTAL				
3					
4	DISTTRIBUTION				
5	NORTH CAROLINA	DIST			
6	SOUTH CAROLINA	DIST			
7	TOTAL	DIST			
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
30	1					1
30	1					2
12	1					3
	1					4
		1				5
3	1					6
3	1					7
3	1					8
20	1					9
20	1					10
20	1					11
20	1					12
12	1					13
12	1					14
10		1				15
10	1					16
10	1					17
10	1					18
10	1					19
10	1					20
10	1					21
185	1					22
185	1		STU			23
185	1		STU			24
300	1					25
300	1		STU			26
300	1		STU			27
300	1		STU			28
336		1				29
50	1		STU			30
200	1					31
448	1					32
45	1					33
448	1					34
1	1		GND	1	500	35
1	1		GND	1	500	36
1	1		GND	1	500	37
9	1		GND	1	9,156	38
1	1					39
560	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
560	1					1
560	1					2
		1				3
560	1					4
560	1					5
560	1					6
1	1					7
1	1					8
10	1					9
10	1					10
20	1					11
20	1					12
20	1					13
20	1					14
20	1					15
20	1					16
20	1					17
20	1					18
20	1					19
20	1					20
20	1					21
2	1					22
2	1					23
2	1					24
1	1					25
1	1					26
1	1					27
2		1				28
		1				29
	1		STU			30
	1		STU			31
	1		STU			32
13	1		STU			33
20	1					34
20	1					35
2		1				36
2	1					37
2	1					38
2	1					39
2		1				40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
2	1					1
2	1					2
2	1					3
3	1					4
3	1					5
3	1					6
15	2					7
20	1					8
20	1					9
12	1					10
12	1					11
12	1					12
12	1					13
20	1					14
20	1					15
20	1					16
13	1					17
20	1		1			18
13	1		1			19
12	1					20
12	1					21
12	1					22
161	1					23
60		1				24
60	1					25
60	1					26
60	1					27
270	1					28
200	1					29
200	1					30
300	1					31
4		1				32
4	1					33
4	1					34
4	1					35
	1		SS			36
1	1		SS			37
3		1				38
3	1					39
3	1					40

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SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
3	1					1
750	1		STU			2
750	1		STU			3
3	1					4
3	1					5
2	1					6
2	1					7
2	1					8
2	1					9
2	1					10
2	1					11
2	1					12
2	1					13
40	1					14
42	1					15
2	1					16
2	1					17
2	1					18
2	1					19
2	1					20
2		1				21
750	1		STU			22
760	1		STU			23
3	1					24
3	1					25
2	1					26
2	1					27
2	1					28
2	1					29
2	1					30
2	1					31
2	1					32
2	1					33
42	1					34
42	1					35
1	1					36
1	1					37
760		1				38
20	1					39
20	1					40

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SUBSTATIONS (Continued)

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30	1					1
30	1					2
10	1					3
10	1					4
	1					5
2		1				6
2	1					7
2	1					8
2	1					9
1		1				10
1	1					11
1	1					12
1	1					13
1	1					14
1	1					15
1	1					16
3		1				17
3	1					18
3	1					19
3	1					20
30	1					21
30	1					22
30	1					23
	1		SS			24
12	1					25
12	1					26
3	1					27
3	1					28
3	1					29
3		1				30
2		1				31
2	1					32
2	1					33
2	1					34
2		1				35
2	1					36
2	1					37
2	1					38
1	1					39
1	1					40

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SUBSTATIONS (Continued)

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1	1					1
10	1					2
10	1					3
12	1					4
10	1					5
13	1					6
13	1					7
20	1					8
2		1				9
3	1					10
3	1					11
3	1					12
10	1					13
30	1					14
30	1					15
	1		SS			16
10	1					17
10	1					18
10	1					19
13	1		1			20
12	1					21
3		1				22
3	1					23
3	1					24
3	1					25
3		1				26
3	1					27
3	1					28
3	1					29
2	1					30
2	1					31
2	1					32
5		1				33
12	1					34
12	1					35
10	1		1			36
10	1					37
10	1		1			38
2	1					39
2	1					40

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SUBSTATIONS (Continued)

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2	1					1
3		1				2
10	1					3
8	1					4
2	1					5
2	1					6
2	1					7
12	1					8
12	1					9
30	1					10
30		1				11
30	1					12
20	1					13
20	1					14
20	1					15
20	1					16
37	1					17
37	1					18
37	1					19
1	1					20
1	1					21
1	1					22
1		1				23
2	1					24
2	1					25
2	1					26
2		1				27
2	1					28
2	1					29
2	1					30
37	1					31
37	1					32
10	1					33
10	1					34
15	1		STU			35
15	1		STU			36
12	1					37
	1					38
	1					39
	1					40

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SUBSTATIONS (Continued)

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20	1					1
20	1					2
12	1					3
12	1					4
2	1					5
2	1					6
12	1					7
13						8
20	1					9
20	1					10
1	1		AUX			11
1	1		AUX			12
1	1		AUX			13
34			STU			14
1	1					15
30		1	STU			16
30		1	STU			17
10	1					18
1	1					19
4	1					20
1	1					21
10	1					22
1	1					23
4	1					24
1	1					25
100	1		STU			26
1	1		AUX			27
1	1					28
1	1					29
1	1					30
1	1					31
1	1					32
1	1					33
62	1		GND	1	61,700	34
8	1					35
8	1					36
2	1					37
2	1					38
2	1					39
2	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
448	1					1
400	1					2
5	1					3
1	1					4
1	1					5
20	1					6
20	1					7
20	1					8
20	1					9
2		1				10
2	1					11
2	1					12
2	1					13
200	1					14
60	1					15
30	1					16
30	1					17
10	1		GND	1	9,561	18
1	1					19
1	1		AUX			20
1	1		AUX			21
1	1		AUX			22
	1		SS			23
20	1					24
30	1					25
20	1					26
20	1					27
20	1					28
20	1					29
20	1					30
20	1					31
1	1					32
1	1					33
1	1					34
1		1				35
200	1		STU			36
140	1		STU			37
12	1					38
12	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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20	1					1
17		1				2
17	1		1			3
12	1					4
12	1					5
30	1					6
30	1					7
30	1					8
10	1					9
	1					10
12	1					11
12	1					12
4	1					13
4	1					14
4	1					15
4		1				16
4	1					17
4	1					18
4	1					19
	1		SS			20
3		1				21
1	1					22
1	1					23
1	1					24
3	1					25
3	1					26
3	1					27
20	1					28
20	1					29
20	1					30
10	1					31
10	1					32
3		1				33
3	1					34
3	1					35
3	1					36
3	1					37
3	1					38
3	1					39
11	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
10	1					1
750	1		STU			2
8	1					3
8	1					4
24	1					5
750	1		STU			6
2	1					7
2	1					8
2	1					9
2	1					10
2	1					11
2	1					12
2	1					13
2	1					14
2	1					15
2	1					16
42	1					17
42	1					18
42	1					19
42	1					20
2	1					21
2	1					22
2	1					23
2	1					24
2	1					25
2	1					26
2	1					27
2	1					28
2	1					29
3	1					30
3	1					31
3	1					32
2	1					33
2	1					34
8	1					35
2	1					36
2	1					37
1	1					38
1	1					39
2	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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3	1					1
750	1		STU			2
2		1				3
2		1				4
8	1					5
8	1					6
24	1					7
750	1		STU			8
2	1					9
2	1					10
2	1					11
2	1					12
2	1					13
2	1					14
2	1					15
2	1					16
2	1					17
2	1					18
42	1					19
42	1					20
42	1					21
42	1					22
2	1					23
2	1					24
2	1					25
2	1					26
2	1					27
2	1					28
2	1					29
2	1					30
3	1					31
3	1					32
3	1					33
2	1					34
2	1					35
8	1					36
10	1					37
10	1					38
10	1					39
10	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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13	1					1
15	1		STU			2
15	1		STU			3
15	1		STU			4
	1					5
336	1					6
224	1					7
336	1					8
448	1					9
29	1		GND	1	28,672	10
10	1		GND	1	9,561	11
1	1		SS			12
1	1		SS			13
1	1		SS			14
2	1					15
3		1				16
3	1					17
3	1					18
10	1					19
10	1					20
10	1					21
10	1					22
10	1					23
10	1					24
30	1					25
30	1					26
30	1					27
	1					28
10	1					29
10	1					30
12	1					31
12	1					32
5		1				33
5	1					34
5	1					35
5	1					36
4		1				37
4	1					38
4	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
1		1				1
1	1					2
1	1					3
1	1					4
12	1					5
12	1					6
12	1					7
	1					8
1	1					9
1	1					10
1	1					11
20	1					12
12	1					13
12	1					14
12	1					15
12	1					16
12	1					17
125	1					18
	1		SS			19
10	1					20
12	1					21
12	1					22
12	1					23
12	1					24
		1				25
7	1					26
7	1					27
7	1					28
	1					29
	1					30
10	1		AUX			31
2	1		GND	1	1,500	32
	1					33
12	1					34
15	1					35
15	1					36
2	1					37
2	1					38
2	1					39
690	1		STU			40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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1	1					1
1	1					2
2	1					3
2	1					4
2	1					5
2	1					6
2	1					7
2	1					8
2	1					9
2	1					10
400	1		AUX			11
300	1					12
10	1					13
11	1					14
15	1					15
15	1					16
4		1				17
4	1					18
4	1					19
4	1					20
	1		SS			21
30	1					22
30	1					23
	1		SS			24
10	1					25
10	1					26
30	1					27
30	1					28
30	1					29
30	1					30
2		1				31
2	1					32
2	1					33
2	1					34
11	1					35
20	1					36
20	1					37
8	1					38
8	1					39
45	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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45	1					1
	1					2
5	1					3
20	1					4
30	1					5
30	1					6
20	1					7
20	1					8
11	1					9
5	1					10
5	1					11
20	1					12
20	1					13
30	1					14
	1		AUX			15
		1				16
22	1					17
20	1		2			18
22	1		2			19
175	1		STU			20
101	1		STU			21
1	1					22
1	1					23
1	1		AUX			24
3		1				25
3	1					26
3	1					27
3	1					28
10	1					29
4		1				30
4	1					31
4	1					32
4	1					33
4	1					34
4	1					35
4	1					36
30	1					37
12	1					38
12	1					39
10	1					40

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5	1					1
10	1					2
11	1					3
30	1					4
30	1					5
	1		AUX			6
20	1					7
20	1					8
10	1					9
4	1					10
17	1		AUTO-TRANSFORMER			11
17	1		AUTO-TRANSFORMER			12
17	1		AUTO-TRANSFORMER			13
76	1		AUTO-TRANSFORMER			14
						15
12	1					16
12	1					17
10	1					18
20	1					19
20	1					20
3		1				21
3	1					22
3	1					23
3	1					24
10	1					25
3	1					26
3	1					27
3	1					28
12	1					29
12	1					30
25	1		STU			31
8	1		STU			32
8	1		STU			33
20	1					34
20	1					35
22	1					36
20	1					37
12	1					38
10	1		GND	1	10,000	39
10	1		GND	1	10,000	40

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SUBSTATIONS (Continued)

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33	1					1
33	1					2
33	1					3
2		1				4
2	1					5
2	1					6
2	1					7
2		1				8
2	1					9
2	1					10
2	1					11
20	1					12
20	1					13
	1		SS			14
12	1					15
3	1					16
3	1					17
3		1				18
3	1					19
10	1					20
10	1					21
15	1					22
34	1					23
34	1					24
34	1					25
	1		SS			26
	1					27
	1					28
	1					29
12	1					30
12	1					31
12	1					32
12	1					33
12	1					34
13	1					35
13	1					36
13	1					37
13	1					38
20	1					39
20	1					40

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SUBSTATIONS (Continued)

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10	1					1
10	1					2
33	1					3
33	1					4
33	1					5
10	1					6
12	1					7
12	1					8
400	1					9
300	1					10
1	1					11
10	1					12
10	1					13
10	1					14
10	1					15
3		1				16
3	1					17
3	1					18
3	1					19
10	1					20
12	1					21
12	1					22
12	1					23
		1				24
3	1					25
3	1					26
3	1					27
	1		SS			28
	1		SS			29
	1		SS			30
10	1					31
10	1					32
20	1					33
20	1					34
10	1					35
10	1					36
12	1					37
12	1					38
12	1					39
12	1					40

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SUBSTATIONS (Continued)

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20	1					1
20	1					2
12	1					3
12	1					4
20	1					5
20	1					6
20	1					7
20	1					8
20	1					9
12	1					10
20	1					11
20	1					12
10	1					13
10	1					14
8	1					15
8	1					16
33	1					17
33	1					18
37	1					19
37	1					20
37	1					21
37	1		2			22
11	1					23
10	1					24
12	1					25
12	1					26
1	1					27
1	1					28
1	1					29
1		1				30
2		1				31
2	1					32
2	1					33
2	1					34
12	1					35
12	1					36
13	1		1			37
30	1					38
30	1					39
12	1					40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
12	1					1
4		1				2
4	1					3
4	1					4
4	1					5
11	1					6
10	1					7
300	1					8
300	1					9
200	1					10
200	1					11
9	1		GND	1	9,145	12
9	1		GND	1	9,156	13
1	1		SS			14
1	1					15
12	1					16
12	1					17
15	1					18
15	1					19
12	1					20
30	1					21
30	1					22
30	1					23
20	1					24
20	1					25
12	1					26
12	1					27
30	1					28
30	1					29
30	1					30
12	1					31
12	1					32
2	1					33
2	1					34
2	1					35
3		1				36
1	1					37
1	1					38
1	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
8	1					1
8	1					2
	1					3
37	1					4
12	1					5
10	1					6
10	1					7
2		1				8
2	1					9
2	1					10
2	1					11
20	1					12
20	1					13
	1					14
	1					15
25	1		STU			16
22	1		STU			17
22	1					18
10	1					19
8	1					20
8	1					21
3		1				22
3	1					23
3	1					24
3	1					25
2	1					26
2	1					27
2	1					28
10	1					29
2	1					30
2	1					31
2	1					32
3		1				33
3	1					34
3	1					35
3	1					36
10	1					37
10	1					38
8	1					39
8	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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10	1					1
20	1					2
20	1					3
20	1					4
20	1					5
30	1					6
30	1					7
11	1					8
11	1					9
11	1					10
11	1					11
11	1					12
11	1					13
10	1					14
20	1					15
20	1					16
6		1				17
6	1					18
6	1					19
6	1					20
6	1					21
6	1					22
6	1					23
	1		SS			24
	1					25
30	1					26
30	1					27
12	1					28
12	1					29
	1					30
12	1					31
12	1					32
20	1					33
3	1					34
3		1				35
3	1					36
3	1					37
12	1					38
13	1					39
2	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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2	1					1
2	1					2
2		1				3
3	1					4
3	1					5
3	1					6
12	1					7
12	1					8
22	1					9
10		1				10
11	1					11
10	1					12
20	1					13
22	1					14
	1					15
20	1					16
20	1					17
10	1					18
10	1					19
5	1					20
2	1					21
2	1					22
2	1					23
20	1					24
20	1					25
20	1					26
12	1					27
12	1					28
12	1					29
12	1					30
12	1					31
13	1					32
22	1					33
20	1					34
30	1					35
30	1					36
30	1					37
1	1					38
1	1					39
1	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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2		1				1
10	1					2
10	1					3
11	1					4
8	1		STU			5
8	1		STU			6
8	1		STU			7
8	1		STU			8
20	1					9
20	1					10
14	1					11
14	1					12
12	1					13
12	1					14
37	1					15
37	1					16
37						17
	1	1				18
6	1					19
6	1					20
6	1					21
37	1					22
37	1					23
33	1					24
33	1					25
33	1					26
20	1					27
20	1					28
4	1					29
4	1					30
4		1				31
4	1					32
4	1					33
4	1					34
4	1					35
4	1					36
4	1					37
4	1					38
	1		SS			39
10	1					40

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SUBSTATIONS (Continued)

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10	1					1
10	1					2
10	1					3
5	1					4
10	1					5
12	1					6
12	1					7
12	1					8
	1		AUX			9
13	1					10
13	1					11
20	1					12
12	1					13
12	1					14
20	1					15
20	1					16
12	1					17
12	1					18
12	1					19
3		1				20
3	1					21
3	1					22
3	1					23
12	1					24
12	1					25
12	1					26
12	1					27
1		1				28
1	1					29
1	1					30
1	1					31
200	1					32
270	1					33
200	1					34
270	1					35
8	1		GND	1	8,230	36
1	1		GND	1	500	37
1	1		GND	1	500	38
1	1		GND	1	500	39
	1		SS			40

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SUBSTATIONS (Continued)

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	1		SS			1
	1		SS			2
10	1					3
8	1					4
1		1				5
2	1					6
10	1					7
2	1					8
2	1					9
12	1					10
12	1					11
20	1					12
20	1					13
20	1					14
10	1					15
22	1		2			16
20	1					17
30	1					18
30	1					19
	1		AUX			20
1		1				21
1	1					22
1	1					23
1	1					24
3	1					25
3	1					26
3	1					27
1		1				28
1	1					29
1	1					30
3	1					31
20	1					32
20	1					33
20	1					34
20	1					35
20	1					36
30	1					37
	1					38
11	1					39
2		1				40

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SUBSTATIONS (Continued)

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2	1					1
2	1					2
2	1					3
1	1					4
1	1					5
1	1					6
5	1					7
5	1					8
10	1					9
10	1		GND	1	10,000	10
20	1					11
20	1					12
30	1					13
30	1					14
30	1					15
20	1					16
20	1					17
3	1					18
3	1					19
3	1					20
3	1					21
3	1					22
3	1					23
20	1					24
20	1					25
20	1					26
12	1					27
	1					28
20	1					29
20	1					30
20	1					31
10	1					32
20	1					33
20	1					34
20	1					35
12	1					36
12	1					37
20	1					38
20	1					39
3		1				40

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SUBSTATIONS (Continued)

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3	1					1
3	1					2
3	1					3
60	1					4
60	1					5
30	1					6
30	1					7
	1		SS			8
	1		SS			9
34						10
	1		SS			11
20	1					12
20	1					13
12	1					14
20	1					15
20	1					16
20	1					17
10	1					18
10	1					19
12	1					20
12	1					21
12	1					22
20	1					23
12	1					24
3		1				25
3	1					26
3	1					27
3	1					28
1	1					29
1	1					30
1	1					31
30	1					32
30	1					33
30	1					34
12	1					35
20	1					36
12	1					37
12	1					38
12	1					39
12	1					40

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SUBSTATIONS (Continued)

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12	1					1
12	1					2
10	1					3
10	1					4
30	1					5
30	1					6
34	1					7
192	1		STU			8
96	1		STU			9
192	1		STU			10
192	1		STU			11
1	1					12
	1					13
1		1				14
1	1					15
1	1					16
1	1					17
1	1					18
	1					19
1	1					20
1	1					21
3	1					22
500	1					23
500	1					24
500	1					25
192		1				26
12	1					27
12	1					28
12	1					29
10	1					30
10	1					31
20	1					32
20	1					33
20	1					34
205	1		STU			35
1		1				36
1	1		AUX			37
1	1		AUX			38
1	1		AUX			39
1	1		AUX			40

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SUBSTATIONS (Continued)

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1	1		AUX			1
4		1				2
4	1					3
4	1					4
4	1					5
4		1				6
4	1					7
4	1					8
4	1					9
		1				10
2	1					11
2	1					12
	1					13
4		1				14
3	1					15
3	1					16
	1					17
10	1					18
10	1					19
30	1					20
30	1					21
10	1					22
8	1					23
12	1					24
12	1					25
20	1					26
20	1					27
3		1				28
3	1					29
3	1					30
3	1					31
10	1					32
10	1					33
20	1					34
22	1		2			35
		1				36
6	1					37
6	1					38
6	1					39
		1				40

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SUBSTATIONS (Continued)

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3	1					1
3	1					2
3	1					3
37	1					4
37	1					5
20	1					6
20	1					7
12	1					8
20	1					9
30	1					10
30	1					11
30	1					12
2	1		GND	1	1,500	13
2	1		GND	1	1,500	14
2	1		GND	1	1,500	15
1	1		GND	1	1,000	16
1	1		GND	1	1,000	17
1	1		GND	1	1,000	18
1		1				19
3		1				20
3	1					21
3	1					22
3	1					23
11	1					24
22	1					25
20	1					26
4		1				27
4	1					28
4	1					29
4	1					30
4	1					31
4	1					32
4	1					33
4	1					34
4	1					35
400	1					36
400	1					37
19	1		GND	1	19,121	38
19	1		GND	1	19,121	39
2	1		SS			40

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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4		1				1
4	1					2
4	1					3
4	1					4
4		1				5
4	1					6
4	1					7
4	1					8
	1		SS			9
1		1				10
1	1					11
1	1					12
1	1					13
12	1					14
12	1					15
3		1				16
3	1					17
3	1					18
3	1					19
10	1					20
10	1					21
10	1					22
10	1					23
3	1					24
3	1					25
3	1					26
12	1					27
12	1					28
13	1		1			29
20	1					30
20	1					31
12	1					32
12	1					33
2	1					34
2	1					35
2	1					36
20	1					37
15	1					38
12	1					39
6		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
6	1					1
6	1					2
6	1					3
6	1					4
6	1					5
6	1					6
3		1				7
3	1					8
3	1					9
3	1					10
10	1					11
20	1					12
20	1					13
20	1					14
32	1		STU			15
32	1		STU			16
22	1					17
20	1					18
2	1					19
2	1					20
2	1					21
3		1				22
10	1					23
20	1					24
20	1					25
30	1					26
30	1					27
	1		SS			28
20	1					29
20	1					30
4		1				31
4	1					32
4	1					33
4	1					34
12	1					35
12	1					36
134	1		STU			37
134	1		STU			38
134	1		STU			39
134	1		STU			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
134	1		STU			1
134	1		STU			2
134	1		STU			3
134	1		STU			4
4		1				5
4	1					6
4	1					7
4	1					8
20	1					9
20	1					10
30	1					11
30	1					12
30	1					13
4		1				14
4	1					15
4	1					16
4	1					17
4	1					18
4	1					19
4	1					20
4	1					21
4	1					22
4		1				23
4	1					24
12	1					25
20	1					26
20	1					27
5	1					28
		1	SS			29
20	1					30
20	1					31
22	1		2			32
12	1					33
12	1					34
7	1		GND	1	6,859	35
12	1					36
12	1					37
12	1					38
10	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
400	1					1
300	1					2
300	1					3
400	1					4
8	1		GND	1	8,230	5
9	1		GND	1	9,145	6
	1					7
	1					8
	1					9
20	1		STU			10
20	1		STU			11
30	1					12
20	1					13
30	1					14
	1		SS			15
12	1					16
12	1					17
12	1					18
12	1					19
13	1					20
30	1					21
30	1					22
30	1					23
10	1					24
10	1					25
12	1					26
20	1					27
20	1					28
13	1					29
15	1					30
17	1					31
	1					32
	1		GND	1		33
	1		GND	1		34
	1		GND	1		35
20	1					36
12	1					37
34	1					38
20	1					39
	1		SS			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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4		1				1
4	1					2
4	1					3
4	1					4
1		1				5
1	1					6
1	1					7
1	1					8
20	1					9
11	1					10
420	1		STU			11
420	1		STU			12
750	1		STU			13
760	1		STU			14
1	1					15
1	1					16
	1					17
	1					18
		1				19
6	1					20
10	1					21
10		1				22
30	1					23
30	1					24
30	1					25
30	1					26
30	1					27
30	1					28
11	1					29
10	1					30
	1					31
20	1					32
20	1					33
20	1					34
150	1					35
30	1					36
1	1		GND	1	500	37
1	1		GND	1	500	38
1	1		GND	1	500	39
	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
	1					1
	1					2
3		1				3
3	1					4
3	1					5
3	1					6
		1				7
560	1					8
500	1					9
500	1					10
2	1					11
	1					12
	1					13
1	1					14
	1					15
	1					16
		1				17
20	1					18
20	1					19
1		1				20
1	1					21
1	1					22
1	1					23
1		1				24
1	1					25
1	1					26
1	1					27
5	1					28
12	1					29
12	1					30
12	1					31
12	1					32
	1		AUX			33
30	1					34
30	1					35
30	1					36
30	1					37
	1					38
	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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20	1					1
20	1					2
20	1					3
20	1					4
20	1					5
20	1					6
12	1					7
12	1					8
12	1					9
12	1					10
	1	1				11
5	1	1				12
5	1	1				13
5	1	1				14
12	1					15
30	1					16
30	1					17
20	1					18
269	1					19
200	1					20
300	1					21
9	1		GND	1		22
9	1		GND	1	9,156	23
	1		SS			24
3		1				25
3	1					26
3	1					27
3	1					28
20	1					29
12	1					30
12	1					31
	1					32
12	1					33
12	1					34
						35
2	1					36
2	1					37
2	1					38
4		1				39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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4	1					1
4	1					2
20	1					3
20	1					4
20	1					5
20	1					6
20	1					7
10	1					8
30	1					9
30	1					10
10	1					11
20	1					12
20	1					13
20	1					14
10	1					15
10	1					16
10	1					17
12	1					18
12	1					19
12	1					20
12	1					21
	1					22
10	1					23
10	1					24
10	1					25
10	1					26
10	1					27
10	1					28
20	1					29
20	1					30
12	1					31
	1		STATION SERVICE			32
			STATION SERVICE			33
200	1					34
150	1					35
150	1					36
30	1					37
30	1					38
1	1					39
12	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
20	1					1
	1					2
2		1				3
2	1					4
2	1					5
2	1					6
6		1				7
10	1					8
10	1					9
10	1					10
3		1				11
3	1					12
3	1					13
3	1					14
10	1					15
10	1					16
1	1					17
1	1					18
1	1					19
2	1					20
	1					21
2	1					22
		1				23
20	1					24
20	1					25
12	1					26
20	1					27
12	1					28
15	1					29
3		1				30
3	1					31
3	1					32
3	1					33
2		1				34
2	1					35
2	1					36
2	1					37
10	1					38
10	1					39
6	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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6	1					1
6	1					2
6		1				3
6	1					4
6	1					5
6	1					6
2		1				7
2	1					8
2	1					9
2	1					10
10	1					11
12	1					12
400	1					13
270	1					14
448	1					15
12	1					16
9	1		GND	1	9,156	17
270						18
2	1		SS			19
200	1					20
200	1					21
200	1					22
200	1					23
19	1		GND	1	19,120	24
19	1		GND	1	19,120	25
	1		SS			26
	1		SS			27
	1		SS			28
8	1					29
8	1					30
22	1					31
20	1					32
12	1					33
12	1					34
20	1					35
20	1					36
20	1					37
27	1					38
27	1					39
15	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

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	1		SS			1
	1		SS			2
	1					3
11	1					4
10	1					5
10	1					6
10	1					7
12	1					8
12	1					9
12	1					10
13	1		1			11
22	1					12
20	1					13
30	1					14
30	1					15
30	1					16
30	1					17
10	1					18
11	1					19
300	1					20
448	1					21
400	1					22
2	1		AUX			23
		1				24
333	1					25
333	1					26
373	1					27
19	1		GND	1	19,120	28
6	1					29
6	1					30
6	1					31
6		1				32
6	1					33
6	1					34
6	1					35
6	1					36
6	1					37
6	1					38
	1		AUX			39
3		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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3	1		STU			1
3	1		STU			2
3	1		STU			3
3	1		STU			4
3	1		STU			5
3	1		STU			6
3		1				7
3		1				8
3		1				9
	1					10
	1					11
	1					12
20	1					13
5	1					14
5	1					15
12	1					16
12	1					17
10	1					18
10	1					19
1						20
5	1					21
20	1					22
20	1					23
4		1				24
4	1					25
4	1					26
4	1					27
448	1					28
200	1					29
224	1					30
200	1					31
9	1		GND	1	9,156	32
1	1		SS			33
12	1					34
12	1					35
5	1					36
5	1					37
5	1					38
4	1					39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
4	1					1
4		1				2
22	1					3
20	1					4
	1		SS			5
22						6
20	1	1				7
12	1					8
16	1					9
240	1					10
4	1					11
	1					12
	1					13
		1				14
		1				15
560	1					16
560	1					17
	1		SS			18
	1		SS			19
1000	1		STU			20
45	1					21
2	1					22
	1					23
2	1					24
2	1					25
2	1					26
2	1					27
2	1					28
2	1					29
2	1					30
2	1					31
	1		AUX			32
30	1					33
52		1				34
2		1				35
2		1				36
1000	1		STU			37
45	1					38
1	1					39
		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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2	1					1
2	1					2
2	1					3
2	1					4
2	1					5
1	1					6
1	1					7
67	1					8
373		1				9
373	1		STU			10
373	1		STU			11
373	1		STU			12
45	1					13
2	1					14
	1					15
2	1					16
2	1					17
2	1					18
2	1					19
2	1					20
1	1					21
1	1					22
45	1					23
12	1					24
15		1				25
12	1					26
22	1					27
22	1					28
5		1				29
5	1					30
5	1					31
5	1					32
2		1				33
2	1					34
2	1					35
2	1					36
11	1					37
37	1					38
37	1					39
2		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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2	1					1
2	1					2
2	1					3
1	1					4
1	1					5
1	1					6
10	1					7
15	1		STU			8
15	1					9
12	1					10
12	1					11
20	1					12
20	1					13
3		1				14
3	1					15
3	1					16
3	1					17
		1				18
200	1					19
200	1		4			20
5	1					21
10	1					22
20	1	1				23
20	1					24
20	1					25
10	1					26
12	1					27
20	1					28
300	1					29
300	1					30
269						31
250		1				32
250	1					33
250	1					34
250	1					35
280	1					36
280	1					37
280	1					38
2	1		SS			39
1	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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20	1					1
20	1					2
20	1					3
20	1					4
200	1					5
200	1					6
400	1					7
29	1		GND	1	28,672	8
29	1		GND	1	28,672	9
1	1		SS			10
400	1					11
400	1					12
12	1					13
19	1					14
1	1					15
19	1					16
12	1					17
12	1					18
20	1					19
20	1					20
5	1					21
5	1					22
20	1	1				23
20	1					24
10	1					25
1	1					26
1	1					27
1	1					28
1		1				29
10	1					30
10	1					31
10	1					32
10	1					33
20	1					34
3		1				35
3	1					36
3	1					37
3	1					38
1	1					39
1	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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1	1					1
12	1					2
12	1					3
12	1					4
3	1		1			5
3	1		1			6
3	1		1			7
2		1	NULL			8
2	1		1			9
2	1		1			10
2	1		1			11
	1		SS			12
12	1					13
12	1					14
12	1					15
20	1					16
20	1					17
20	1					18
20	1					19
4		1				20
4	1					21
4	1					22
4	1					23
4	1					24
4	1					25
4	1					26
	1					27
22	1		1			28
20	1					29
30	1					30
30	1					31
34	1					32
200	1					33
200	1					34
30	1					35
60	1					36
60	1					37
19	1		GND	1	19,120	38
9	1		GND	1	9,145	39
1	1		SS			40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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20	1					1
20	1					2
20	1					3
	1					4
10	1					5
300	1					6
300	1					7
300	1					8
		1				9
500	1					10
500	1					11
500	1					12
29	1		GND	1	28,672	13
		1				14
	1		SS			15
1	1					16
30	1					17
30	1					18
20	1					19
22	1					20
	1					21
1	1					22
4	1					23
1	1					24
1	1					25
8	1					26
10	1					27
10	1					28
8	1					29
10	1					30
34	1					31
30	1	1				32
30	1					33
20	1					34
20	1					35
20	1					36
20	1					37
20	1					38
20	1					39
12	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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12	1					1
30	1					2
30	1					3
30	1					4
20	1					5
20	1					6
20	1					7
20	1					8
20	1					9
12	1					10
15	1					11
12	1					12
4	1					13
4	1					14
4	1					15
4	1					16
4		1				17
4	1					18
4	1					19
20	1					20
20	1					21
12	1					22
12	1					23
20	1					24
20	1					25
30	1					26
30	1					27
30	1					28
15	1		STU			29
15	1		STU			30
15	1		STU			31
30	1					32
30	1					33
	1					34
13	1					35
12	1					36
4		1				37
4	1					38
4	1					39
4	1					40

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20	1					1
20	1					2
	1					3
12	1					4
12	1					5
448	1					6
448	1					7
13	1					8
13		1				9
13	1					10
13	1					11
13	1					12
10	1		STU			13
	1		GND	1		14
	1		GND	1		15
	1		GND	1		16
2	1		GND	1	1,667	17
10	1					18
10	1					19
34	1					20
12	1					21
12	1					22
10		1				23
6	1					24
6	1					25
6	1					26
12	1					27
12	1					28
20	1					29
20	1					30
8	1		STU			31
8	1		STU			32
8	1		STU			33
8	1		STU			34
1	1					35
1	1					36
20	1					37
20	1					38
4		1				39
4	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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4	1					1
4	1					2
		1				3
	1					4
	1					5
4	1					6
4	1					7
4	1					8
4	1					9
	1					10
5	1					11
		1				12
5	1					13
5	1					14
5	1					15
5	1					16
5	1					17
20	1					18
20	1					19
22	1					20
20	1					21
20	1					22
22	1					23
10	1					24
2		1				25
2	1					26
2	1					27
2	1					28
10	1					29
10	1					30
400	1					31
400	1					32
448	1					33
1	1		AUX			34
29	1		GND	1	28,672	35
10	1					36
10	1					37
30	1					38
30	1					39
10	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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5	1					1
8	1					2
8	1					3
10	1					4
8	1					5
22	1					6
20	1					7
10	1					8
17	1					9
448	1					10
400	1					11
19	1		GND	1	19,120	12
1	1					13
20	1					14
20	1					15
3	1					16
3	1					17
3	1					18
4		1				19
4	1					20
4	1					21
4	1					22
4	1					23
4	1					24
4	1					25
3		1				26
3	1					27
3	1					28
3	1					29
	1					30
2	1					31
2	1					32
1	1					33
1	1					34
1	1					35
2		1				36
2	1					37
12	1					38
2		1				39
2	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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2	1					1
2	1					2
2	1					3
2	1					4
2	1					5
34	1					6
34	1					7
	1		SS			8
10	1					9
10	1					10
10	1					11
10	1					12
10	1					13
20	1					14
22	1					15
20	1					16
20	1					17
12	1					18
12	1					19
34	1					20
34	1					21
20	1					22
20	1					23
2	1					24
2	1					25
2	1					26
2		1				27
20	1					28
20	1					29
12	1					30
300	1					31
300	1					32
19	1		GND	1	19,120	33
19	1		GND	1	19,120	34
2	1		SS			35
2		1				36
2	1					37
2	1					38
2	1					39
1	1					40

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SUBSTATIONS (Continued)

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1	1					1
1	1					2
20	1					3
20	1					4
20	1					5
20	1					6
10	1					7
10	1					8
3		1				9
3	1					10
3	1					11
3	1					12
300	1					13
200	1					14
200	1					15
10	1		GND	1	9,561	16
10	1		GND	1	9,561	17
1	1					18
1	1					19
1	1					20
11	1					21
11	1					22
22	1					23
10	1					24
10	1					25
10	1					26
20	1					27
20	1					28
20	1					29
12	1					30
20	1					31
20	1					32
10	1					33
10	1					34
6		1				35
6	1					36
6	1					37
6	1					38
20	1					39
	1		SS			40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
20	1					1
20	1					2
12	1					3
	1		GND	1		4
20	1					5
30	1					6
12	1					7
12	1					8
13	1		1			9
22	1		1			10
270	1					11
400	1					12
400	1					13
1	1					14
1	1					15
3		1				16
3	1					17
3	1					18
3	1					19
10	1					20
10	1					21
20	1					22
12	1					23
20	1					24
20	1					25
20	1					26
20	1					27
20	1					28
12	1					29
4		1				30
4	1					31
4	1					32
4	1					33
4	1					34
4	1					35
4	1					36
34	1					37
30	1					38
20	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
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20	1					1
30	1					2
30	1					3
	1					4
20	1		GND	1	20,000	5
22	1					6
12	1					7
12	1					8
12	1					9
22	1					10
20	1					11
37	1					12
20	1					13
20	1					14
20	1					15
20	1					16
25	1		1			17
30	1		1			18
45	1		4			19
5	1		1			20
	1		1			21
12	1					22
12	1					23
20	1					24
20	1					25
10	1					26
11	1					27
	1					28
10	1					29
10	1					30
10	1					31
10	1					32
9	1		GND	1	9,145	33
	1					34
4		1				35
4	1					36
4	1					37
4	1					38
30	1					39
34	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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20	1					1
20	1					2
4	1					3
4	1					4
4	1					5
	1					6
4		1				7
22	1					8
22	1					9
12	1					10
12	1					11
10	1		STU			12
20	1					13
20	1					14
4		1				15
4	1					16
4	1					17
4	1					18
3		1				19
3	1					20
3	1					21
3	1					22
9		1				23
9	1		STU			24
9	1		STU			25
9	1		STU			26
50	1					27
30	1					28
5	1					29
1	1		GND	1	1,000	30
1	1		GND	1	1,000	31
1	1		GND	1	1,000	32
	1		SS			33
20	1					34
20	1					35
336	1					36
200	1					37
448	1					38
9	1		GND	1	9,145	39
8	1		GND	1	8,230	40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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1	1					1
1	1					2
2		1				3
2	1					4
2	1					5
2	1					6
3	1					7
3	1					8
3	1					9
12	1					10
12	1					11
12	1					12
38	1					13
38	1					14
12	1					15
20	1					16
20	1					17
1		1				18
1	1					19
1	1					20
1	1					21
3		1				22
3	1					23
3	1					24
3	1					25
2	1					26
2	1					27
2	1					28
2	1					29
2	1					30
2	1					31
10	1					32
10	1					33
20	1					34
20	1					35
12	1					36
12	1					37
20	1					38
20	1		REG			39
1		1				40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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1	1					1
1	1					2
1	1					3
2		1				4
2	1					5
2	1					6
3	1					7
2		1				8
2	1					9
2	1					10
2	1					11
2		1				12
2	1					13
2	1					14
2	1					15
10	1					16
	1					17
37	1					18
37	1					19
20	1					20
20	1					21
3	1					22
3	1					23
3	1					24
3		1				25
3	1					26
3	1					27
3	1					28
2		1				29
2	1					30
2	1					31
2	1					32
10	1					33
11	1					34
250	1					35
250	1					36
1	1					37
1	1					38
10	1					39
10	1					40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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4	1					1
	1					2
	1					3
4	1					4
2	1		STU			5
2	1		STU			6
2	1		STU			7
10	1		GND	1	9,561	8
	1					9
	1					10
	1					11
3	1					12
3	1					13
3	1					14
3		1				15
12	1					16
20	1					17
20	1					18
34	1					19
34	1					20
30	1					21
30	1					22
12	1					23
12	1					24
20	1					25
20	1					26
22	1					27
12	1					28
13	1					29
65	1		STU			30
5	1					31
5	1					32
5	1					33
10	1					34
10	1					35
6		1				36
6	1					37
6	1					38
6	1					39
20	1					40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	
4		1				1
4	1					2
4	1					3
4	1					4
10	1					5
2		1				6
2	1					7
2	1					8
3	1					9
1		1				10
1	1					11
1	1					12
1	1					13
1	1					14
1	1					15
1	1					16
20	1					17
12	1					18
	1					19
20	1					20
20	1					21
20	1					22
2		1				23
2	1					24
2	1					25
2	1					26
20	1					27
20	1					28
37	1					29
37	1					30
37	1					31
10	1					32
5	1					33
12	1					34
12	1					35
3		1				36
3	1					37
3	1					38
3	1					39
2		1				40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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2	1					1
2	1					2
2	1					3
12	1					4
12	1					5
4	1					6
4	1					7
4	1					8
12	1					9
20	1					10
20	1					11
20	1					12
20	1					13
12	1					14
12	1					15
12	1					16
12	1					17
	1		SS			18
20	1					19
20	1					20
	1		SS			21
	1		SS			22
13	1					23
13	1					24
20	1					25
37	1					26
14	1					27
		1				28
3	1					29
		1				30
2	1					31
10	1					32
2	1					33
2	1					34
2	1					35
2	1					36
10	1					37
10	1		STU			38
10	1		STU			39
10	1		STU			40

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Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

SUBSTATIONS (Continued)

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10	1		STU			1
10	1		STU			2
	1					3
	1					4
	1					5
1	1					6
1	1					7
1	1					8
10	1					9
2		1				10
10	1					11
12	1					12
20	1					13
10	1					14
10	1					15
45	1					16
45	1					17
10	1					18
10	1					19
	1					20
13	1					21
12	1					22
12	1					23
12	1					24
12	1					25
		1				26
	1					27
	1					28
	1					29
10	1					30
12	1					31
20	1					32
20	1					33
5		1				34
5	1					35
5	1					36
5	1					37
20	1					38
20	1					39
20	1					40

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SUBSTATIONS (Continued)

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20	1					1
20	1					2
30	1					3
30	1					4
20	1					5
20	1					6
	1					7
20	1					8
12	1					9
4		1				10
4	1					11
4	1					12
4	1					13
1		1				14
1	1					15
1	1					16
1	1					17
4		1				18
4	1					19
4	1					20
4	1					21
12	1					22
12	1					23
12	1					24
200	1					25
448	1					26
336	1					27
336	1					28
	1		AUX			29
	1		GND	1	28,672	30
	1		GND	1	9,561	31
20	1					32
11	1					33
20	1					34
20	1					35
20	1					36
20	1					37
20	1					38
300	1					39
300	1					40

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SUBSTATIONS (Continued)

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300	1					1
1	1		AUX			2
29	1		GND	1	28,672	3
29	1		GND	1	28,672	4
8	1					5
8	1					6
12	1					7
30	1					8
30	1					9
	1					10
20	1		1			11
20	1					12
15	1		STU			13
15	1		STU			14
15	1		STU			15
15	1		STU			16
12	1					17
12	1					18
22	1					19
22	1					20
6		1				21
6	1					22
6	1					23
6	1					24
5	1					25
10	1					26
10	1					27
12	1					28
12	1					29
1	1					30
1	1					31
1	1					32
12	1					33
22	1		1			34
12	1					35
86032	2470	204		70	711,745	36
						37
						38
65	1					39
46013	586	30				40

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SUBSTATIONS (Continued)

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23055	421	32				1
69133	1008	62				2
						3
						4
12784	1030	95				5
4115	432	47				6
16899	1462	142				7
						8
						9
						10
						11
						12
						13
						14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
						35
						36
						37
						38
						39
						40

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TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Services provided by Duke Energy Business Services	Duke Energy Business Services, LLC	Various	941,611,601
3				
4	Customer & Market services	Duke Energy Progress, LLC	Various	8,501,075
5	Generation services	Duke Energy Progress, LLC	Various	31,285,789
6	Other goods and services	Duke Energy Progress, LLC	Various	5,004,338
7	Transmission and Distribution services	Duke Energy Progress, LLC	Various	27,580,077
8				
9	Customer & Market services	Duke Energy Florida, LLC	Various	1,903,895
10	Generation services	Duke Energy Florida, LLC	Various	802,994
11	Other goods and services	Duke Energy Florida, LLC	Various	171,134
12	Transmission and Distribution services	Duke Energy Florida, LLC	Various	2,981,105
13				
14	Customer & Market services	Duke Energy Indiana, LLC	Various	57,674
15	Generation services	Duke Energy Indiana, LLC	Various	582,015
16	Other goods and services	Duke Energy Indiana, LLC	Various	297,462
17	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	766,987
18				
19				
20	**Non-power Goods or Services Provided for Affiliate**			
21	Services provided to DE Business Services, LLC	Duke Energy Business Services, LLC	Various	21,712,605
22				
23	Customer & Market services	Duke Energy Progress, LLC	Various	56,132,884
24	Generation services	Duke Energy Progress, LLC	Various	561,488,566
25	Other goods and services	Duke Energy Progress, LLC	Various	40,230,113
26	Transmission and Distribution services	Duke Energy Progress, LLC	Various	49,643,306
27				
28	Customer & Market services	Duke Energy Florida, LLC	Various	26,112,925
29	Generation services	Duke Energy Florida, LLC	Various	12,067,478
30	Other goods and services	Duke Energy Florida, LLC	Various	16,042,363
31	Transmission and Distribution services	Duke Energy Florida, LLC	Various	23,294,834
32				
33	Customer & Market services	Duke Energy Indiana, LLC	Various	26,477,940
34	Generation services	Duke Energy Indiana, LLC	Various	10,235,566
35	Other goods and services	Duke Energy Indiana, LLC	Various	8,922,491
36	Transmission and Distribution services	Duke Energy Indiana, LLC	Various	13,539,155
37				
38	Customer & Market services	Duke Energy Kentucky, Inc.	Various	5,593,766
39	Generation services	Duke Energy Kentucky, Inc.	Various	10,478,790
40	Other goods and services	Duke Energy Kentucky, Inc.	Various	1,152,166
41	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	2,033,136
42				
1	**Non-power Goods or Services Provided by Affiliated**			
2	Customer & Market services	Duke Energy Ohio, Inc.	Various	84,404

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Duke Energy Carolinas, LLC	(1) [X] An Original (2) [ ] A Resubmission	04/14/2020	End of 2019/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Gas Distribution Services	Duke Energy Ohio, Inc.	Various	4,768
4	Other goods and services	Duke Energy Ohio, Inc.	Various	
5	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	778,475
6				
7	Customer & Market services	Duke Energy Kentucky, Inc.	Various	
8	Gas Distribution Services	Duke Energy Kentucky, Inc	Various	
9	Generation services	Duke Energy Kentucky, Inc.	Various	
10	Other goods and services	Duke Energy Kentucky, Inc.	Various	
11	Transmission and Distribution services	Duke Energy Kentucky, Inc.	Various	
12				
13	Gas Distribution Services	Piedmont Natural Gas Company, Inc.	Various	2,797,471
14				
15	Other goods and services	North/South Insurance Co		6,613,738
16				
17	Other goods and services	Duke Energy Commercial Enterprises	Various	1,591,203
18				
19	Other goods and services	DEGS Holding Co		328,545
20	**Non-power Goods or Services Provided for Affiliate**			
21	Customer & Market services	Duke Energy Ohio, Inc.	Various	30,698,030
22	Generation services	Duke Energy Ohio, Inc.	Various	258,429
23	Other goods and services	Duke Energy Ohio, Inc.	Various	1,021,884
24	Transmission and Distribution services	Duke Energy Ohio, Inc.	Various	10,197,064
25				
26	Customer & Market services	Piedmont Natural Gas Company, Inc.	Various	6,100,927
27	Generation services	Piedmont Natural Gas Company, Inc.	Various	28,043
28	Other goods and services	Piedmont Natural Gas Company, Inc.	Various	659,546
29	Transmission and Distribution services	Piedmont Natural Gas Company, Inc.	Various	924,265
30				
31	Other goods and services	Duke Energy One, Inc.	Various	345,821
32				
33	Other goods and services	Cinergy Solutions	Various	13,859,817
34				
35				
36				
37				
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40				
41				
42				

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When an employee of the Service Company performs services for a Client Company, costs will be directly assigned or distributed or allocated. For allocated services, the allocation method will be on a basis reasonably related to the service performed. The Service Company Utility Service Agreement prescribes 23 Service Company functions and approximately 20 allocation methods.

Functions and Allocation Methods:

Information Systems
- Number of Central Processing Unit Seconds Ratio/Millions of Instructions per Second
- Number of Personal Computer Workstations Ratio
- Number of Information Systems Servers Ratio
- Number of Employees Ratio

Meters
- Number of Customers Ratio

Transportation
- Number of Employees Ratio
- Three Factor Formula

Electric System Maintenance
- Circuit Miles of Electric Transmission Lines Ratio
- Circuit Miles of Electric Distribution Lines Ratio

Marketing and Customer Relations and Grid Solutions
- Number of Customers Ratio

Electric Transmission & Distribution Engineering & Construction
- Electric Transmission Plant's Construction - Expenditures Ratio
- Electric Distribution Plant's Construction - Expenditures Ratio

Power Engineering & Construction
- Electric Production Plant's Construction - Expenditures Ratio

Human Resources
- Number of Employees Ratio

Supply Chain
- Procurement Spending Ratio
- Inventory Ratio

Facilities
- Square Footage Ratio

Accounting
- Three Factor Formula
- Generating Unit MW Capability Ratio

Power Planning and Operations
- Electric Peak Load Ratio
- Weighted Avg of the Circuit Miles of Electric Distribution Lines Ratio and the Electric Peak Load Ratio
- Sales Ratio
- Weighted Avg of the Circuit Miles of Electric Transmission Lines Ratio and the Electric Peak Load Ratio
- Generating Unit MW Capability Ratio

Public Affairs
- Three Factor Formula
- Weighted Avg of Number of Customers Ratio and Number of Employees Ratio

Legal
- Three Factor Formula

Rates
- Sales Ratio

Finance
- Three Factor Formula

Rights of Way
- Circuit Miles of Electric Transmission Lines Ratio

FOOTNOTE DATA

- Circuit Miles of Electric Distribution Lines Ratio
- Electric Peak Load Ratio

Internal Auditing

- Three Factor Formula

Environmental, Health and Safety

- Three Factor Formula
- Sales Ratio

Fuels

- Sales Ratio

Investor Relations

- Three Factor Formula

Planning

- Three Factor Formula

Executive

- Three Factor Formula

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